DOE/FETC-97/1053
(DE97005456)
CONF-970121

Proceedings of the Fifth Annual Clean Coal Technology Conference

January 7-10, 1997
Tampa, Florida

Co-sponsors:
U.S. Department of Energy
Center for Energy & Economic Development
National Mining Association
Electric Power Research Institute
Council of Industrial Boiler Owners

Contents

This primary contents page has been set up with each section (or session) title linked to the corresponding section/session. To use this feature, move your cursor to the section/session you wish to view. (Your cursor arrow will change to a pointing finger.) Click your left mouse button to jump to the beginning of that section/session.

Disclaimer

Foreword

Papers and Presentations

Opening Plenary Session: Powering the Next Millennium: Challenges in Meeting the Goal

Panel Session 1: Issue 1: International Markets for CCTs

Panel Session 2: Issue 2: Role of CCTs in the Evolving Domestic Electricity Market

Panel Session 3: Issue 3: Environmental Issues Affecting CCT Deployment

Panel Session 4: Issue 4: CCT Deployment From Today Into the Next Millennium

Closing Plenary Session: Powering the Next Millennium: CCT Answers the Challenge

Technical Session I: Advanced Coal Process Systems

Technical Session II: Advanced Industrial Systems

Technical Session III: Advanced Cleanup Systems

Technical Session IV: Advanced Power Generation Systems

Disclaimer

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government or any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

To return to the primary *Contents* page or the Cover, click the **Go Back** button (the double left-pointing arrow) from the tool bar at the top of the screen, or choose **Go Back** from the view menu.

Foreword

The Fifth Annual Clean Coal Technology Conference focused on presenting strategies and approaches that will enable clean coal technologies to resolve the competing, interrelated demands for power, economic viability, and environmental constraints associated with the use of coal in the post-2000 era.

The program addressed the dynamic changes that will result from utility competition and industry restructuring, and the evolution of markets abroad. Current projections for electricity highlight the preferential role that electric power will have in accomplishing the long-range goals of most nations. Increased demands can be met by utilizing coal in technologies that achieve environmental goals while keeping the cost-per-unit of energy competitive. Results from projects in the DOE Clean Coal Technology Demonstration Program confirm that technology is the pathway to achieving these goals.

The industry/government partnership, cemented over the past 10 years, is focused on moving the clean coal technologies into the domestic and international marketplaces. The Fifth Annual Clean Coal Technology Conference provided a forum to discuss these benchmark issues and the essential role and need for these technologies in the post-2000 era.

To return to the primary *Contents* page or the Cover, click the **Go Back** button (the double left-pointing arrow) from the tool bar at the top of the screen, or choose **Go Back** from the view menu.

Opening Plenary Session

Powering the Next Millennium: Challenges in Meeting the Goal

This session contents page has been set up with each presentation title linked to the corresponding presentation. To use this feature, move your cursor to the presentation you wish to view. (Your cursor arrow will change to a pointing finger.) Click your left mouse button to jump to the beginning of that presentation.

KEYNOTE ADDRESS: VISION AND CHALLENGE TO ENSURE THAT CCTs CONTRIBUTE IN THE NEXT MILLENNIUM

Anderson, Girard F.

TECO Energy

ISSUE 1: INTERNATIONAL MARKETS FOR CCTs

Ferriter, John P.

International Energy Agency

ISSUE 2: ROLE OF CCTs IN THE EVOLVING DOMESTIC ELECTRICITY MARKET

Gordon, Kenneth

National Economic Research Associates, Inc.

LUNCHEON ADDRESS: ISSUE 4: CLEAN COAL TECHNOLOGY DEPLOYMENT: FROM TODAY INTO THE NEXT MILLENNIUM

Papay, Lawrence T., Trocki, Linda K. and McKinsey, Ronald R.

Bechtel Technology and Consulting

To return to the primary *Contents* page or the Cover, click the **Go Back** button (the double left-pointing arrow) from the tool bar at the top of the screen, or choose **Go Back** from the view menu.

Panel Session 1

Issue 1: International Markets for CCTs

This session contents page has been set up with each presentation title linked to the corresponding presentation. To use this feature, move your cursor to the presentation you wish to view. (Your cursor arrow will change to a pointing finger.) Click your left mouse button to jump to the beginning of that presentation.

REGIONAL TRENDS IN THE TAKE-UP OF CLEAN COAL TECHNOLOGIES
Wootten, John M.
Peabody Holding Company, Inc.

INDUSTRY PERSPECTIVES ON INCREASING THE EFFICIENCY OF COAL-FIRED POWER GENERATION
Torrens, Ian M.
Shell Coal International

Stenzel, William C.
SEPRIL Services

To return to the primary *Contents* page or the Cover, click the **Go Back** button (the double left-pointing arrow) from the tool bar at the top of the screen, or choose **Go Back** from the view menu.

Panel Session 2

Issue 2: Role of CCTs in the Evolving Domestic Electricity Market

This session contents page has been set up with each presentation title linked to the corresponding presentation. To use this feature, move your cursor to the presentation you wish to view. (Your cursor arrow will change to a pointing finger.) Click your left mouse button to jump to the beginning of that presentation.

CCT'S IN A DEREGULATED ENVIRONMENT: A PRODUCER'S PERSPECTIVE
Edmonds, Robert F., Jr. and Fayssoux, John O.
Duke Power Company

MARKET FOR NEW COAL POWERPLANT TECHNOLOGIES IN THE U.S.; 1997 ANNUAL ENERGY OUTLOOK RESULTS
Hutzler, Mary J.
U.S. Department of Energy

THE ROLE OF CLEAN COAL TECHNOLOGIES IN A DEREGULATED RURAL UTILITY MARKET
Neal, John W.
National Rural Electric Cooperative Association

To return to the primary *Contents* page or the Cover, click the **Go Back** button (the double left-pointing arrow) from the tool bar at the top of the screen, or choose **Go Back** from the view menu.

Panel Session 3

Issue 3: Environmental Issues Affecting CCT Deployment

This session contents page has been set up with each presentation title linked to the corresponding presentation. To use this feature, move your cursor to the presentation you wish to view. (Your cursor arrow will change to a pointing finger.) Click your left mouse button to jump to the beginning of that presentation.

DOMESTIC ENVIRONMENTAL REQUIREMENTS, NEW AND PROJECTED
McLean, Brian
U.S. Environmental Protection Agency

LEGISLATIVE ISSUES RELATING TO CCTs
Reidy, Maura
Representative to the Interior Appropriations Subcommittee
Office of Representative Sidney Yates, U.S. House of Representatives

Wainman, Barbara
Assistant to the Chairman, Interior Appropriations Subcommittee
U.S. House of Representatives

To return to the primary *Contents* page or the Cover, click the **Go Back** button (the double left-pointing arrow) from the tool bar at the top of the screen, or choose **Go Back** from the view menu.

Panel Session 4

Issue 4: CCT Deployment From Today Into the Next Millennium

This session contents page has been set up with each presentation title linked to the corresponding presentation. To use this feature, move your cursor to the presentation you wish to view. (Your cursor arrow will change to a pointing finger.) Click your left mouse button to jump to the beginning of that presentation.

A UTILITY PERSPECTIVE ON THE DEPLOYMENT OF CCT'S INTO THE NEXT MILLENNIUM
Mudd, Michael J.
American Electric Power Energy Services

A CHICKEN IN EVERY POT A NEW BOILER IN EVERY POWERPLANT A NEW POWERPLANT AT EVERY INDUSTRlAL SITE
Bessette, Robert D.
Council of Industrial Boiler Owners

IN ORDER TO BE SUCCESSFUL, TECHNOLOGY MUST ADAPT TO THE CHANGES IN THE MARKETPLACE
Houck, James C.
Texaco, Inc.

CONSOL'S PERSPECTIVE ON CCT DEPLOYMENT
Burke, F. P. and Statnick, R. M.
CONSOL Inc.

STATE REPRESENTATIVE PERSPECTIVE
Moreland, Terri
State of Illinois Washington Office

To return to the primary *Contents* page or the Cover, click the **Go Back** button (the double left-pointing arrow) from the tool bar at the top of the screen, or choose **Go Back** from the view menu.

Closing Plenary Session

Powering the Next Millennium: CCT Answers the Challenge

This session contents page has been set up with each presentation title linked to the corresponding presentation. To use this feature, move your cursor to the presentation you wish to view. (Your cursor arrow will change to a pointing finger.) Click your left mouse button to jump to the beginning of that presentation.

COMPLETING THE CCT MISSION: THE CHALLENGE OF CHANGE
Monk, James R.
Illinois Energy Association

ISSUE 1: INTERNATIONAL MARKETS: SEIZING THE OPPORTUNITY
Heyes, Alan
UK Department of Trade and Industry

ISSUE 2: DOMESTIC ELECTRICITY MARKET PERSPECTIVE FOR CCTs
Grahame, Tom
U.S. Department of Energy

ISSUE 3: ENVIRONMENTAL ISSUES AFFECTING COAL AND CCTs INTO THE NEXT MILLENNIUM
Hausker, Karl
Center for Strategic and International Studies

ISSUE 4: ADVANCED COAL TECHNOLOGY: IT WILL MAKE A DIFFERENCE!
Eminger, Randy
The Center for Energy & Economic Development

FEATURED SPEAKER
The Honorable Ralph Regula
U.S. House of Representatives

To return to the primary *Contents* page or the Cover, click the **Go Back** button (the double left-pointing arrow) from the tool bar at the top of the screen, or choose **Go Back** from the view menu.

Technical Session I

Advanced Coal Process Systems

This session contents page has been set up with each presentation title linked to the corresponding presentation. To use this feature, move your cursor to the presentation you wish to view. (Your cursor arrow will change to a pointing finger.) Click your left mouse button to jump to the beginning of that presentation.

RECENT EXPERIENCE WITH THE CQE™

Harrison, Clark D. and Kehoe, David B.
CQ Inc.

0'Connor, David C.
Electric Power Research Institute

Stallard, G. Scott
Black & Veatch

SELF-SCRUBBING COAL-AN INTEGRATED APPROACH TO CLEAN AIR

Harrison, K. E., PE
Custom Coals Corporation

ROSEBUD SYNCOAL PARTNERSHIP SYNCOAL® DEMONSTRATION TECHNOLOGY UPDATE

Sheldon, Ray W., P.E.
Rosebud SynCoal Partnership

To return to the primary *Contents* page or the Cover, click the **Go Back** button (the double left-pointing arrow) from the tool bar at the top of the screen, or choose **Go Back** from the view menu.

Technical Session II

Advanced Industrial Systems

This session contents page has been set up with each presentation title linked to the corresponding presentation. To use this feature, move your cursor to the presentation you wish to view. (Your cursor arrow will change to a pointing finger.) Click your left mouse button to jump to the beginning of that presentation.

AN UPDATE ON BLAST FURNACE GRANULAR COAL INJECTION
Hill, D. G., Strayer, T. J. and Bouman, R. W.
Bethlehem Steel Corporation

CLEAN POWER FROM INTEGRATED COAL-ORE REDUCTION
Wintrell Reginald
Geneva Steel

MiIler, Robert N., Harbison, Edmund J. and LeFevre, Mark O.
Air Products

England, Kevin S.
Centerior Energy

ROLE OF THE LIQUIDS FROM COAL PROCESS IN THE WORLD ENERGY PICTURE
Frederick, James P. and Knottnerus, Brent
ENCOAL Corporation

LUNCHEON ADDRESS: CHANGING FACE OF INTERNATIONAL POWER GENERATION
Lindsay, Ian
World Energy Council

To return to the primary *Contents* page or the Cover, click the **Go Back** button (the double left-pointing arrow) from the tool bar at the top of the screen, <u>or</u> choose **Go Back** from the view menu.

Technical Session III

Advanced Cleanup Systems

This session contents page has been set up with each presentation title linked to the corresponding presentation. To use this feature, move your cursor to the presentation you wish to view. (Your cursor arrow will change to a pointing finger.) Click your left mouse button to jump to the beginning of that presentation.

THE CLEAN COAL TECHNOLOGY PROGRAM 10 MW_e DEMONSTRATION OF GAS SUSPENSION ABSORPTION FOR FLUE GAS DESULFURIZATION

Hsu, Frank E. and Hedenhag, Jorgen G.
AirPol, Inc.

Marchant, Sharon K., Ph.D., and Pukanic, George W., Ph.D.
U.S. Department of Energy

Norwood, Verrill M., Ph.D. and Burnett, Thomas A.
Tennessee Valley Authority

SMALL, MODULAR, LOW-COST COAL-FIRED POWER PLANTS FOR THE INTERNATIONAL MARKET

Zauderer, B., Frain, B. and Borck, B.
Coal Tech Corp.

Baldwin, A. L.
U. S. Department of Energy

CHIYODA THOROUGHBRED CT-121 CLEAN COAL PROJECT AT GEORGIA POWER'S PLANT YATES: PHASE II RESULTS

Burford, David P.
Southern Company Services, Inc.

THE HEALY CLEAN COAL PROJECT AN OVERVIEW

Olson, John B., P.E. and McCrohan, Dennis V., P.E.
Alaska Industrial Development and Export Authority

To return to the primary *Contents* page or the Cover, click the **Go Back** button (the double left-pointing arrow) from the tool bar at the top of the screen, or choose **Go Back** from the view menu.

Technical Session III

Advanced Cleanup Systems

(Continued)

This session contents page has been set up with each presentation title linked to the corresponding presentation. To use this feature, move your cursor to the presentation you wish to view. (Your cursor arrow will change to a pointing finger.) Click your left mouse button to jump to the beginning of that presentation.

COAL REBURNING FOR COST-EFFECTIVE NO_x COMPLIANCE

Folsom, B. A., Sommer, T. M., Engelhardt, D. A. and Moyeda, D. K
Energy and Environmental Research Corporation

Rock, R. G.
Eastman Kodak Company

0'Dea, D. T.
New York State Electric and Gas

Hunsicker, Scott
Fuller Power Corporation

Watts, J. U.
U.S. Department of Energy

THE NOXSO CLEAN COAL PROJECT

Black, James B., Woods Mark C, Friedrich, John J. and Browning, John P.
NOXSO Corporation

To return to the primary *Contents* page or the Cover, click the **Go Back** button (the double left-pointing arrow) from the tool bar at the top of the screen, or choose **Go Back** from the view menu.

Technical Session III

Advanced Cleanup Systems

(Continued)

This session contents page has been set up with each presentation title linked to the corresponding presentation. To use this feature, move your cursor to the presentation you wish to view. (Your cursor arrow will change to a pointing finger.) Click your left mouse button to jump to the beginning of that presentation.

INTEGRATED DRY NO_x/SO_2 EMISSIONS CONTROL SYSTEM PERFORMANCE SUMMARY

Hunt, Terry
Public Service Company of Colorado

Muzio, Lawrence J. and Smith, Randall
Fossil Energy Research Corporation

Jones, Dale
BTU Services

Hebb, Jerry L.
U.S. Department of Energy

Stallings, Jeff
Electric Power Research Institute

To return to the primary *Contents* page or the Cover, click the **Go Back** button (the double left-pointing arrow) from the tool bar at the top of the screen, or choose **Go Back** from the view menu.

Technical Session IV

Advanced Power Generation Systems

This session contents page has been set up with each presentation title linked to the corresponding presentation. To use this feature, move your cursor to the presentation you wish to view. (Your cursor arrow will change to a pointing finger.) Click your left mouse button to jump to the beginning of that presentation.

WABASH RIVER COAL GASIFICATION REPOWERING PROJECT-FIRST YEAR OPERATION EXPERIENCE

Troxclair, E. J.
Destec Energy, Inc.

Stultz, Jack
PSI Energy, Inc.

McINTOSH UNIT 4 PCFB DEMONSTRATION PROJECT

Dodd, Alfred M.
Lakeland Electric & Water

Dryden, Richard J.
Foster Wheeler Development Corporation

Morehead, Harry T.
Westinghouse Electric Corporation

To return to the primary *Contents* page or the Cover, click the **Go Back** button (the double left-pointing arrow) from the tool bar at the top of the screen, or choose **Go Back** from the view menu.

JERRY ANDERSON
CLEAN-COAL CONFERENCE
KEYNOTE ADDRESS

JANUARY 8, 1997

Thank you, Chuck, and good morning everyone.

On behalf of our sponsors, and your host utility, I'd like to welcome you all to Tampa and the Fifth Annual Clean Coal Technology Conference.

Tampa Electric is extremely proud to serve as host for this prestigious international conference on "clean-coal technologies that will power the next millennium."

The focus of this conference is the presentation of innovative strategies for the 21st Century that will meet the demands for electric power, economic viability and environmental awareness – all connected with the use of coal.

It promises to be an exciting and informative conference.

Now, let me tell you a little about your host city. Tampa is the business and financial hub of West Central Florida and one of the fastest-growing urban areas in the country.

The Tampa-St. Petersburg metro area is the largest in Florida, with more than two million people.

In fact, it's the second largest in the Southeast behind only Atlanta, and 19th in size in the country.

Many high-tech and high-quality companies agree this is a prime location for business, and have established substantial operations here.

Companies such as Time, Salomon Brothers, Citibank, Disney, Capital One and Beneficial.

There's also a business and construction boom going on in downtown Tampa, particularly along our waterfront.

Our Florida Aquarium celebrates its second anniversary next month, having drawn well over a million visitors since its opening in 1995.

A few blocks away, hockey fans and concert-goers are flocking to the Ice Palace, our new 21,000-seat downtown arena.

Another one of our community's major assets, particularly as a business resource, is the University of South Florida.

A major public university that's leading our state into the 21st Century, USF has also been on the cutting edge of research, innovation and developing new technologies.

Citing just one example, the university's College of Engineering has been actively engaged in the Nineties with Florida's key utilities, including Tampa Electric Company, in researching solar power and electric vehicles.

And, Tampa Electric has worked closely with USF in researching and demonstrating advanced electric technologies at our Electric Technology Resource Center, located on the university's main campus in Tampa.

I hope you have a chance while you're here to see some of the places I've mentioned and more of our beautiful Tampa Bay area, and why we're proud to call it home.

Tampa Electric Company has served the energy needs of this growing and dynamic Tampa Bay market since 1899.

Today, the utility has more than half-a-million customers and close to 3,000 employees.

Tampa Electric's parent company, TECO Energy, is also headquartered here in Tampa. It is one of Florida's largest utility holding companies.

TECO Energy's stock is publicly traded on the New York Stock Exchange and is owned by more than 33,000 shareholders.

Besides Tampa Electric, TECO Energy's family of energy-related companies are involved in water transportation, coal mining, natural gas production, home automation and energy management, engineering and energy services, and wholesale power generation. We have facilities and offices in several states, and in Central America.

Our family of diversified companies experienced rapid growth in 1996.

Last month, we acquired a Tampa-based engineering and energy services company, which provides a wide range of services to commercial customers throughout Florida and in California.

And, in November, TECO Energy agreed to merge with Lykes Energy, the Tampa-based parent of Peoples Gas System, Florida's largest natural gas distribution company.

We expect to complete the merger by the middle of this year. And when we do, we will add Peoples' 1,100 employees, 200,000-plus customers and $300-million in revenues to our diversified business base.

Now, to the subject of this conference, how clean-coal technologies will power the next millennium.

During the conference, you'll have the opportunity to see first-hand how Tampa Electric and the Department of Energy are meeting that 21st Century challenge at the Polk Power Station.

This 250-megawatt, power generating facility, located about 40 minutes east of Tampa in southwestern Polk County, demonstrates the value of public-private partnerships – like ours between the DOE and Tampa Electric.

We are extremely pleased and appreciative to have the DOE as partners in this project, and for bringing this fifth annual clean-coal conference to Tampa.

The DOE has played a key role in the success of the project by co-funding its innovative technology – providing $140 million through its Clean Coal Technology Program to demonstrate this first-of-its-kind technology application.

DOE's partnership and commitment is enabling us to apply these advanced power generation technologies commercially for the first time.

And, we look forward to hearing the DOE perspective on the Polk project and the future of clean-coal technologies from DOE Secretary Hazel O'Leary on Friday, when she helps us formally dedicate the Polk Power Station.

The Polk project also is the product of another successful public-private partnership that broke new ground in the selection of a site for this new power plant.

In fact, it's the first U.S. power plant ever located through community input.

Seven years ago, we gave the people in this community a real voice in where we would build our next power plant.

We relied upon the recommendations of a citizens power plant siting task force to determine the best location for this facility.

Meeting and working in the sunshine, an independent coalition of educators, business and community leaders and environmentalists evaluated 35 potential power plant sites in six West Central Florida counties. They did that over a year's time, before recommending three inland Polk County locations.

Tampa Electric followed the task force's recommendation even though the site that group selected did not meet traditional economic evaluations.

The site we selected DID, however, have the least impact on the environment and the surrounding community.

I expect it is also the lowest overall cost because of the relative ease and speed of its permitting process.

For this innovative work, the Siting Task Force and Tampa Electric garnered a number of environmental awards, including the 1991 Florida Audubon Society Corporate Award, the 1993 Timer Powers Conflict Resolution Award from the state of Florida and the 1993 Ecological Society of America corporate award.

We also received praise from government leaders, utility regulators and the news media for putting this critical choice in the hands of the public.

The Polk Power Station operating today is one of the cleanest, most efficient and economical coal-fired plants in the U.S.

The plant went on line this fall on schedule and on budget, just two years after tthe start of construction.

At Tampa Electric, we are very proud of having been able to bring this $500-million project into our utility rate base with NO increase in prices to our customers.

Last year, the Florida Public Service Commission approved an innovative proposal, which will freeze Tampa Electric's base rates through 1999.

And, the plant actually reduces the average cost of electricity because of its high thermal efficiency and use of low-cost coal.

For Tampa Electric, the Polk Power Station means a clean, economic and efficient source of power – 10-12 percent more efficient than conventional, coal-fired units, and the first unit on Tampa Electric's system to dispatch.

At the same time, we've taken several steps to protect, preserve, and in fact, enhance, the area's environment.

The Polk project was the first utility power plant ever built on old phosphate mining land.

We started our environmental efforts by reclaiming the property, planting some 200 acres of trees and creating 600 acres of lakes.

We've minimized the plant's impact on its immediate surroundings by establishing a protected 1,500-acre recreational preserve, which includes wetlands, uplands and five fishing lakes that will be managed by the Florida Game and Fresh Water Fish Commission.

This expansive natural habitat also provides space for nesting bird islands and osprey platforms.

So, at the Polk Power Station, we're balancing the need for a healthy, diverse environment, with the need for a reliable, efficient energy supply.

The plant's clean-coal technology meets the latter need by fully integrating two leading technologies: combined-cycle turbine, which is the most efficient commercially available method of producing electricity, and coal gasification, which converts coal into a clean-burning synthetic gas.

This project differs from other integrated-gasification, combined-cycle, or IGCC, plants, because it will be completely integrated – from coal gas production to turbine generator operation.

For example, Tampa Electric owns and operates the 150-ton-per-hour air separation unit.

Pure oxygen is required for the operation of the coal gasifier to produce the synthetic gas, which is burned in the combustion turbine.

The high-pressure nitrogen product from the unit is piped to the combustion turbine, generating additional electricity, lowering the combustion temperature and thereby reducing the formation of nitrogen oxides.

By integrating the plant, we'll enhance the high-efficiency of the facility's combined-cycle with the low cost of coal for its fuel.

This plant represents the most advanced electric technology from the power generation side. Now, I'd like to share with you how Tampa Electric is applying advanced electric technologies at the point of end use.

It's happening today at our utility's Electric Technology Resource Center.

The ETRC, located adjacent to the main entrance of the University of South Florida, is Florida's first full-service demonstration facility for electric technologies.

The ETRC is an interactive demonstration facility that allows Tampa Electric's business customers – restaurants, retailers, manufacturers – to come in and try out the newest technologies before they invest and change their methods of operation.

The ETRC features three demonstration areas: One for advanced electric technology, one for commercial foodservice and a lighting display center.

Since it opened just over a year ago, the ETRC has held over 1,000 seminars and events for manufacturers, vendors and business customers; welcomed more than 4,000 visitors; and partnered with more than 100 electric technology equipment makers.

There will be a tour of the ETRC for conference delegates this afternoon, and I hope you'll take the opportunity to visit this showplace for exciting new electric technologies.

Tampa Electric expects that these technologies will increase our customers' competitiveness, improve their productivity and strengthen our area's economy.

And, that's especially important for electric utilities as the industry changes into a more competitive marketplace.

All of us with an interest in coal as a source of energy, should also recognize that this changing political and business environment could affect utilities' use of coal in the 21st Century.

Certainly, any legislative or regulatory change in the way utilities do business has the potential for a major impact on the coal industry.

In the United States, coal will remain the major primary fuel source for the foreseeable future.

What is not clear is the share of new source electric generation that will be coal fired.

Part of this uncertainty is caused by changing environmental regulation.

These environmental concerns are successfully being addressed by the clean-coal program through projects such as our Polk IGCC plant.

However, global competitive pressures are forcing changes in the electric utility business. You will be hearing about those changes at this conference.

In general, I believe increased competition should result in greater utilization of existing coal-fired plants because of their low incremental cost.

The probable near-term effect on the coal industry is positive, with an increase in demand. It is more difficult to estimate the long-term effect.

Changes in the regulatory environment will make it more difficult for utilities to make large, long-term capital commitments.

This uncertainty about the future is the negative that faces the coal industry and the advancement of clean-coal technologies for the longer term.

The initial investment in a clean-coal gasification plant is three times the investment in a natural gas or light oil-fired plant.

Even though that higher initial cost is more than paid off over the life of the plant, it is still a difficult investment decision.

Let me quickly add that I believe we have found the successful formula here in Florida.

As you have heard, we serve a growing community that is environmentally aware.

We have no easy inexpensive sources of energy here, and we simply must provide affordable energy that makes our businesses competitive in a world market.

The coupling of our nation's abundant coal resources with the technology you will see here has allowed us to meet all of these challenges.

Yes, it took thought and care and planning. But with the help of many of you and with the support of the Department of Energy, we have achieved our goal:

- A new source of electric energy, competitively priced – clean, reliable and ready to fuel our future growth.

I know you will benefit from the insights you gain at this conference.

I hope you like what you see here in Florida, and that you enjoy your stay in Tampa.

– END –

INTERNATIONAL MARKETS FOR CCTs

Mr. John P. Ferriter, Deputy Executive Director
International Energy Agency

FIFTH ANNUAL CLEAN COAL TECHNOLOGY CONFERENCE
JANUARY 7-10, 1997
TAMPA, FLORIDA

INTRODUCTION

The Role of the IEA

Let me start with a few remarks about the International Energy Agency.

The IEA was created in 1974, in response to the first oil shock to ensure its Members' collective energy security. At that time, the essence of energy security was seen as an uninterrupted oil supply.

Attention focused on developing emergency preparedness measures to respond to a major disruption in the international flow of crude oil, and on promoting long-term cooperation and research and development activities among Members to reduce their dependence on imported oil.

While these activities continue today as fundamental elements of the Agency's work, events of the last several years, in particular the end of the Cold War, have dramatically altered the world political and economic scene, and thus changed the basic environment in which world energy markets function:

- The economic restructuring under way in former communist countries, coupled with the expected continuation of strong incremental energy demand in non-OECD Asia and elsewhere in the developing world, will have significant effects upon both the supply and demand sides of international energy markets - these are now becoming truly "global".

- The resulting world energy balance is shifting, with the OECD now accounting for only half of global energy consumption.

- Energy markets generally have evolved, with deregulation and liberalisation resulting in their being driven more by market forces than through government intervention, although government involvement is clearly still required in certain instances.

- Environmental effects associated with the energy sector, from production through to consumption, have become increasingly vexing and compel innovative approaches to energy policy.

Importance of Coal

The response by energy policy makers to these challenges must draw on coal for a major contribution.

- Coal is one of the world's most important and abundant fossil fuels; its share of many countries' energy mix and the wide distribution of reserves around the world enhance diversity, and thus increase energy security.

- There is major scope for improving the efficiency with which coal is used and for mitigating the pollution and other emissions that its production and use can cause.

- Coal is low-cost compared with oil or gas, perhaps between a quarter and one-half the price for the same primary energy content. Many countries have economically viable domestic resources of coal to support economic development.

What is the IEA doing in the area of Clean Coal Technology?

The IEA Secretariat conducts a wide range of policy research, at the direction of its Members, on energy technology, energy-environment, and energy diversification issues. Much of this is concerned with advising governments on the market conditions required for optimising decisions on economic and energy-environment issues.

Important work of relevance to clean coal technology is also conducted by groups of our Member Countries, which come together to carry out work in areas of particular interest to them. These are known as Implementing Agreements. The oldest of these, IEA Coal Research - The Clean Coal Centre, publishes a wide range of studies, from basic coal science through exploration and production, to coal beneficiation, transport and use. The environmental dimension of each part of the coal chain is ever more important in the decision making process, and is therefore increasingly represented in IEA Coal Research publications.

Other Implementing Agreements on coal include:

- The Coal Combustion Sciences Agreement which is concerned with the basic science of coal combustion, including the development and application of analytical techniques for the analysis of coal combustion processes.

- The Fossil Fuel Multiphase-Flow Sciences Agreement, which coordinates the exchange of information and complementary research tasks in a wide range of research programmes to improv understanding of the behaviour and properties of multiphase phenonema associated with obtaining energy from coal, oil and gas.

- The Fluidised Bed Conversion Programme, which is sharing information about, and collaboratively researching, the physical and chemical processes which occur during fluidised bed conversion, in atmospheric and pressurised fluidised combustion beds, both bubbling and circulating.

Some recent highlights of our work show the approach we are taking in support of the clean coal technologies.

In early December, I led an IEA team at a conference on energy efficiency in Beijing, which we organised with the State Planning Commission. A major part of the conference was devoted to coal development, and coal utilisation in China. Papers presented by the IEA side sought to promote the clean and efficient production and use of coal.

Similarly, in October last year, we organised a joint workshop with the World Bank on the financing of clean coal technologies. The seminar brought together policy makers, financial institutions, equipment manufacturers, and research organisations.

In 1995, the US Department of Energy and other bodies sponsored an IEA Conference on *The Strategic Value of Fossil Fuels: Challenges and Responses*.

We will shortly publish a major study on electricity in Asia, the *Asian Electricity Study*, which examines the electricity sectors in Indonesia, the Philippines, and Thailand. A chapter of the report is devoted to issues of power plant finance.

We have also published a number of reports covering coal issues generally. These include a report on the *Energy Policies of the Russian Federation* (1995), the *Energy Policies of South Africa* (1996), both with coal chapters. Each year we publish *Coal Information*, a major compilation of coal statistics with extensive commentary on coal production, demand and trade. The Coal Information series also provides current information on coal-fired power stations under construction and in planning throughout the world, including those using advanced power generation technology.

As a final example from many activities related to your conference, we have formal recognition at the on-going negotiations on climate change. We are at present developing advice for consideration at the Conference of the Parties (known as COP-3) to be held at the end of this year, and which could have a major bearing on the future of coal.

Role of the IEA Coal Industry Advisory Board

The IEA has a specialist industry source of advice on coal - the Coal Industry Advisory Board. The CIAB currently has 45 Members, representing coal industry interests from 16 countries. Members are corporate leaders from coal production, transport and utilisation companies.

Membership is not limited to OECD Member Countries. In 1995, the CIAB gained two new Members fro Africa, from Eskom and Ingwe. This year I hope we might make progress in gaining Members from Chin the world's largest producer of coal and a key player in international coal trade.

The CIAB is vitally concerned with promoting the use of clean coal technologies. The Board has produce a series of three reports published by the IEA* on clean coal technologies, examining industry attitudes to the take-up of both gasification/combined cycle, and advanced steam cycle technologies.

The CIAB studies confirm that there is a wide range of state-of-the-art coal-fired technologies suitable for different conditions in both developed and developing countries. These range from large scale supercritical steam-cycle power generation, through smaller scale fluidised bed plants for power generation and industrial heat, to IGCC technology which is under demonstration for very clean power generation.

Progress in installing such technologies is still slower than had been hoped and expected. Nevertheless, supercritical steam cycle plants are successfully established in Japan, Germany, and Denmark, and there is no shortage of industrial scale and demonstration plants for many of the other technologies.

The CIAB has been studying reasons for this slower progress and is now examining what may be done to accelerate the adoption of advanced coal-fired technology in different regions. The IEA expects to publish a new report from the CIAB, looking at the regional factors influencing the take-up of clean coal technologies, during 1997.

Context for discussing Clean Coal Technologies

The IEA's *World Energy Outlook* (1996) shows the secure future for coal.

We take two cases, which we call the Capacity Constraints case and the Energy Savings case. In the Capacity Constraints case trends in past behaviour are assumed to continue to dominate future energy consumption patterns. In the energy savings case energy consumers choose to use available energy efficient technology to an extent greater than has been seen in the past.

Three major conclusions can be drawn from the projections:

- First, world primary energy demand is expected to continue to grown steadily, as it has grown over the last two decades.

- Second, fossil based fuels will account for almost 90% of total primary energy demand in 2010.

- Third, a structural shift in the shares of different regions in world energy demand is likely to occur - the OECD share of world energy demand will fall in favour of the rest of the world, where the share of world primary energy demand is expected to rise from 28% now, to almost 40% in 2010.

In general terms, the outlook for coal in the world energy scene is for strong competition with gas, weakening demand for some coal uses, but continuing demand for baseload power generation.

Demand for solid fuels - principally coal - is expected to rise steadily in the outlook period to 2010 (at an average annual rate of 1.7% - 2.2%). Overall, the share of solid fuels in the primary fuel mix is likely to remain stable, but there will be significant changes in the pattern of world solid fuels consumption:

- Countries such as China and India, are very coal intensive. Growth in coal demand in the non-OECD countries could be as high as 3.8% per annum, and use in power generation could be as hig as 6% per annum.

- In the OECD countries, coal is expected to be increasingly a fuel for power generation. In 1993, the OECD was the largest fuel consuming region. By 2010, however, the OECD could acco for only just over one-third of world solid fuel consumption. The Rest of the World could consume more than on-half of world solid fuel.

The messages from our projections for your conference are:

- Coal has, and will retain, a central role in meeting the world's future energy needs.

- The growth area of coal use is in power generation.

- In OECD countries, coal's share in the electricity output mix will be maintained, but coal demand for other uses will fall.

- In the Rest of the World, coal will lose share in final energy consumption, but use in power generation will grow at over 6 percent per annum. The region where attention needs to be focused is Asia.

Technology Choices

Which Coal Technologies will be Chosen?

These messages are good news for coal producers, and seemingly so for coal technology developers and manufacturers. I mentioned earlier that the CIAB has expressed concern about the slower-than-expected take-up of the clean coal technologies. Let me review the evidence for this.

In the OECD countries, tighter emission standards are encouraging interest in clean coal technologies. But there is little prospect for growth in coal use in these countries taken as a whole.

Where growth prospects are greatest, in the Asia-Pacific region, Independent Power Producers are the key to power generation investment in the Asian region. The choices they make on technology will be decisive in determining if clean coal technologies are used.

The CIAB has conducted a survey of Independent Power Producers (IPPs) in several regions, as part of the regional study I mentioned earlier. Sixteen companies involved in independent power generating project development and/or construction were surveyed. Several of the surveyed companies also represented technology supply or engineering/construction firms.

The survey found that at present, IPPs will choose mainly sub-critical pulverised-coal technology (that is, conventional coal-fired power generation technology), and in some cases Atmospheric Fluidised Bed (AFBC) technology. This technology can be clean and economic. Sulphur dioxide, NOx ar particulates can be reduced to acceptable levels, and provide low-cost electricity. At present, environmental standards, especially in developing economies, do not require environmental performance beyond the range of conventional plant with add-on pollution control.

Local and regional environmental problems from sulphur dioxide, NOx and particulates can be addressed by available technology, and there is a generally accepted policy framework for governments to adopt to ensure that emissions are controlled in an economically efficient manner.

As an aside, Flue Gas Desulphurisation at the power station would generally be regarded as the technology of choice for reducing sulphur dioxide emissions. This is not always the case. In China, for example, coal use is 70% in direct applications, and only 30% in power generation. During the IEA's recent conference on energy efficiency in China, which I mentioned earlier, coal preparation was described as the highest priority in clean coal technology for China because it would reduce emissions from direct use of coal.

However, on a global level, CO_2 emissions from power generation are becoming increasingly the focus of attention for energy policy makers. The higher levels of conversion efficiency which can be achieved by advanced steam cycle and gasification/combined cycle technologies, are desirable on global environmental grounds.

When asked what their expectations were for 2005, the IPPs responded that they would expect more supercritical steam cycle plants, and Pressurised Fluidised Bed Combustion (PFBC) in specialist uses, but Integrated Gasification Combined Cycle (IGCC) technology would not be in widespread use for coal before 2010.

The factors influencing these views were given as:

- Reliability, technology cost and financing constraints are the most important factors influencing the choice of technology.

- Government regulation, maintainability, technology risk and lender attitudes came a close second.

- Environment was not seen as a major determining factor. But environmental considerations would be important if contained in the category of government regulation, listed as important.

- Need for skilled operators came low on the list of factors, as IPPs felt it is not difficult to find and train them.

What are the problem areas?

The survey revealed that the advanced steam cycle technologies are considered to be commercially proven, but to be more costly and riskier, especially when built in non-OECD countries.

There are more than 350 supercritical units operating world-wide. Their early technical problems have been overcome and improvements incorporated in areas such as metallurgy, equipment design and water treatment. The reliability of these plants is now considered as good as for sub-critical plants. Nonetheless, the IPPs surveyed were cautious in selecting this form of clean coal technology.

IGCC was considered to be too costly to compete without some form of support.

Accelerating the Take-up of Clean Coal Technologies

What can be done?

In looking at what might be done to accelerate the use of the advanced clean coal power generation technologies, three points are clear:

- The regions where rapid growth in coal-fired power generation is occurring, are viewed by developers as having a different investment environment from the OECD countries. In short, there are more risks involved and, possibly, conventional risks are higher.

- Policies to encourage the take-up of advanced clean coal technologies need to be narrowly targeted, since the problems are different for the different parts of the world and for different technologies. Policies may need to be designed to suit particular regions and particular technologies.

- Governments should not be left to cope with the task. It is in the long-term interests of the coal industry to be actively involved.

General Prescription

There is a general prescription for encouraging the take-up of clean coal technologies in power generation:

- Electricity costs from plants *with* pollution control cannot be expected to drop dramatically, or drop below those *without* pollution control, unless completely new technologies are developed. These may be possible, but they are not on the horizon today.

- Consequently, clean coal technologies will be chosen when environmental regulations require them.

- Environmental regulations will be applied when environmental costs to society are recognised.

IEA Coal Research published a report in 1995, *Air Pollution Control Costs for Coal-fired Power Stations*, which quantified the cost of air pollution control costs for coal-fired power stations. They found that for new installations, the costs of sulphur dioxide and NOx control account for about 15% to 20% of the cost of electricity, depending on emission limits, the technology chosen and other technical and economic factors. Particulate control adds 3% to 4% to the cost of electricity.

It is unavoidable that as more stringent emissions controls are imposed, the cost of electricity also rises. For currently available technologies, the price rises steeply as different technologies are used to attain the next higher level of performance.

We know from the experience with control of sulphur dioxide, NOx, and particulates, that once Governments decide on minimum standards of performance, the market will choose the most cost-effective way of meeting the standards. It is important to a cost-effective outcome that Governments do not attempt to impose the particular type of technology which should be used.

At the moment, there is no generally agreed standard which might encourage higher levels of conversion efficiency in plants. Economics determines the level of efficiency considered appropriate in a particular circumstance. As I have already commented, at present power developers in the high growth Asian economies are satisfied with the level of performance that can be attained by conventional sub-critical plant. They can meet all environmental requirements with this type of technology, with add-on pollution control such as Flue Gas Desulphurisation, if necessary.

In the absence of private economic incentive to use clean coal technology, then more advanced technologies will not be chosen until Governments choose to place a higher value on environmental performance, including carbon dioxide. Of course, developers might then turn away from coal if competing fuels, particularly gas, are more economic under a stricter environmental regime.

In the past, Governments have seen their role as supporting the take-up of new technologies in many fields, through direct financial support such as support for research and development, demonstration plants, and capital subsidies. There can be little doubt that programmes along these lines have advanced the technology and economics of clean coal power generation.

But enthusiasm for such measures is waning, under pressure of budget constraints.

Where clean coal technologies are commercially competitive, the situation is fairly straight forward. Governments have a role to develop sound environmental regulations, and to strive for undistorted energy markets where fuel prices reflect costs, including environmental costs.

For the technologies which are close to commercial or not yet generally accepted as proven, the situation is more complex, possibly calling for a range of policy measures.

Generally speaking, measures usually discussed all involve a degree of market intervention. We should be certain we understand the market before interventionist measures are implemented. At least three areas of the market need to be looked at:

- Is there genuine competition between electricity producers? Producers should be obliged by market conditions or regulation to look at the relative economics of the different technologies, and not be guided, say, to give preference to one form of technology over another because it is manufactured in the same country.

- Similarly, is there genuine competition between technology suppliers?

- Have external costs of power generation been taken into account?

Once we have a sound understanding of these points, we can look at measures governments might take to promote clean coal technologies.

A variety of measures have been proposed to complement the more traditional direct financial assistance measures. In listing these measures, I am not suggesting that the IEA necessarily gives its endorsement. Measures which have been proposed include, for example,

- Promotional measures to break down perception barriers concerning the use of coal, and to disseminate information on available, commercially proven, advanced clean coal technologies.

- Certainly, coal has a poor image and countries with major national interests in coal production have a particular responsibility here.

- The CIAB takes the view that there is insufficient understanding of the current reliability and economics of supercritical power generation technology, and has sought to address this by undertaking an analysis (still underway) of costs and other issues relevant in comparing sub-critical, supercritical and ultra-supercritical pulverised coal plants in non-OECD countries.

- Sharing the risk: This might take the form of Governments providing assurances against political risk for new developments, while manufacturers offer longer warranty periods to reduce technology risks. These measures would not be designed to direct a developer to a particular technology, but rather to ensure the developer's choice was not prejudiced.

- Developing "innovative" financing packages for new developments. This suggestion is based on the assumption that the risk-averse nature of lenders will influence technology choices.

- Activities Implemented Jointly (AIJ). AIJ has been proposed as a means by which countries might achieve reductions in global emissions of carbon dioxide, by projects and activities conducted outside their borders. The result could be a greater reduction in emissions, at lower cost, than the country might achieve within its own borders.

- In a comparison made by the CIAB, based on hypothetical 600 MW pulverised coal plants, the annual mass of carbon dioxide emissions for conventional, supercritical and ultra-supercritical plants are 5.2 million short tons, 4.8 million short tons, and 4.4 million short tons, respectively.

- This represents a reduction in emissions of 8% for supercritical, and 15% for ultra-supercritical plants, compared with conventional plant. There is scope for huge reductions in carbon dioxide emissions from Asia, through the use of these technologies.

These proposals are generally at the conceptual stage, and your conference would be making a major contribution if it could develop some ideas, either to further develop those I have listed, or as additional suggestions for promoting clean coal technologies.

The measures I have described should not necessarily replace all the more direct forms of encouragement I mentioned. Research and development, promotion of technology development and deployment, and technology cooperation are all proper roles for government in relation to coal technology. The decline in expenditure in these areas is to be regretted.

Nonetheless, industry has an important role in ensuring the future of coal. The coal industry needs to look to its own long-term interest, and companies along the length of the coal chain - from production to utilisation - should see that their interests are bound up in the future of the clean coal technologies.

At the end of this year, at the third Conference of the Parties on climate change, to be held in Japan, there is a very real prospect that legally binding targets on Greenhouse Gas emissions will be agreed. Such a proposal was put forward by the US Government at the second conference, held last year. If this is the outcome, then clean coal technologies will play a vital role in helping coal-fired power generation meet the new standards expected, in those countries which are party to any agreement emerging.

It would be short-sighted to think that any agreement at COP-3 would not eventually impact on those countries not immediately involved in the climate negotiations. It would also be short-sighted to imagine that failure to agree at COP-3 will signal an end to the debate on energy-climate issues.

Today we might usefully focus on how the clean coal technologies can provide a constructive, and economic, response to maintain coal's prominent position in the world energy scene.

Thank you.

* *Industry Attitudes to Combined Cycle Clean Coal Technologies* (IEA OECD, 1994)
Industry Attitudes to Steam Cycle Clean Coal Technologies (IEA OECD, 1995)
Factors Affecting the Take-Up of Clean Coal Technologies (IEA OECD, 1996)

ROLE OF CCTs IN THE EVOLVING DOMESTIC ELECTRICITY MARKET

Kenneth Gordon
Senior Vice President
National Economic Research Associates, Inc.

Fifth Annual Clean Coal Technology Conference
Tampa, Florida
January 7-10, 1997

Thank you Assistant Secretary Godley. It's very good to be here. It is a real pleasure to be at a another DOE conference.

Take just a moment to thank DOE for sponsoring this as indeed it has sponsored Conferences on a wide variety of topics that I am concerned with.

I think the very first joint NARUC DOE Conference dealt with gas issues that occurred while I was still President of NARUC and I had the opportunity to help put that one together. Subsequently, conferences have been established to bring regulators and other interested parties together to talk about electricity issues and those conferences have been enormously successful in advancing the debate in helping understanding of these issues and it's nice to see it going on in areas that aren't quite as close to the ones that I am concerned with on a daily basis.

Let me offer a couple of disclaimers here. First the title, I'm not an expert on Clean Coal Technologies it will not surprise, I guess many of you to learn. But rather focus on the electricity markets from a regulators and economist now perspective and so I'm going to talk about the environment within which clean coal technologies, but for that matter other technologies as well, will find themselves, I think, over the next few years, and probably indefinitely.

I'm going to talk mostly about the United States, that means I'll be bringing home some of the ideas and issues that John was talking about just a few moments ago. These are world wide trends toward competitive electricity markets at the generation and they are going to change the way the world works. I was struck by one of John's comments toward the end of his talk. He talked about perceptions and the way in which people look at coal.

One of my tasks while I was Chairman of the Massachusetts Department of Public Utilities was to be Chair of the Energy Facility Siting Board of Massachusetts. While I was there, we considered (there isn't a lot of building going on but never the least we did consider) a few projects. Two of them, coal projects, and it was interesting, to me, the degree of resistance that was felt to those projects, although they were in complete compliance with all the relevant environmental laws.

Now you know that coal is not a heavily used fuel in New England, but never the lest it has some market there, and I assume would like to have more. There were serious perception issues that the fuel, just as a fuel, even apart from the technologies that were being used, and I think conferences like this and outreach of the sort that I know some of you do, really is important to bring these things home where they can be environmentally acceptable.

Well there are substantial changes taking place in the domestic electricity markets and world wide. In the United States the FERC, in Washington, and the State Commissions particularly a few states, is driving the changes. Fundamental changes, underlie these policy shifts, what is going on is not just a change in attitude that regulators have, that policy makers have, there is technology change, particularly as it affects optimal generation scale. There is no longer the perception that bigger is necessary, in order to be economical, in order to be optimal. New technologies have changed that calculus. There's lowered transaction cost, the ability to organize more complex markets perhaps that's impart a function of the information revolution, and the communication revolutions, a kind of sister regulated area that I also spend time dealing with, our experience in other industries.

We've seen increased reliance on a market operate successfully, in airlines, throughout the transportation industries, in the telecommunications industries and there's no longer any reason to believe the way we did 10 or 20 years ago, that network industries are some how different, some how special. They may still have their own peculiar special aspects but major portions of them are capable, we think of being competitive and operate on a market basis, the ability of markets to handle formerly vertically integrated arrangements, the whole notion of what is the firm, what is the relevant firm, is changing and that's not different from other industries including unregulated industries, so the restructuring that has happened elsewhere is happening here.

Now I don't know what the future electricity industry is going to look like, I know how we're going to get started with regulators taking certain steps. Some of the early determinants of the structure will involve the separation of retailing functions and generation functions from transportation. Transportation meaning transmission and distribution. Continuing regulation of the transportation (if you want to call it that), through new regulator devises such as performance-based regulation that seems to be the near term step that's being taken and in my old territory of Massachusetts, the largest electricity company **NES** has announced that it will spend off all of its generation and operate itself as a distribution company. The transmission is slightly in New England to be separated completely from any of the other functions. John Howe, my successor and Rich Coward, a month or two (a couple months ago, I guess maybe it's longer than that, time does fly when you're having fun), presented a manifesto' on Independent System Operators that I think that may have commanded a good deal of attention. I think NEPOL, my old pool in the New England area is going to look very different very soon in order to support more effectively the development of competitive markets.

Now we don't know what the outcomes are going to be indeed the point of relying on markets is that we don't know what the right outcome is and so we want to facilitate this process of finding a more efficient future. The forecast the people are making today about five or ten years in the future are probably almost certainly indeed off the mark. So with that cavitate, let me turn to what is happening and what may unfold.

The industry as it has been recently, until recently. Vertically integrated, franchise monology or the practical equivalent, that is ending. Through-going regulation at the state and federal levels, monology the norm. While the monology is ending, I'm not sure the regulation will end right away, but it will shift its focus to questions of access, to questions of interconnection and openness and will get away from the kind of regulation that focused on the utilities planning its resource planning, the impact of environmental constraints, the application of specific technologies, all of that stuff that was done in the old regulated mechanisms, first by utility managements and practically for many years only by utility managements, is going to shift a bit. The firm is an administrative operation.

People make decisions in firms based on whatever information they have in the old regulated utility sector. They didn't face very many constraints in deciding how to proceed. That was the rate base, regulated rate of return world (and I'm not going to go into that in any detail), but the problems that were associated with it are one of the reasons that an evolution has taken place and moved us toward a different world. But the first move away from traditional rate base regulation was not to rely us on markets for planning it was through integrated resource planning going under a variety of names in different places. Both at the state and federal level, support of integrated resource planning was the first response to perceived serious difficulties with the old rate of return rate base regulated systems, and integrated resource planning involves the substitution of a broader set of participants in the administrative planning process.

It was no longer just the firm but a broader set of interveners, very often including environmentalist, some times customers, low income advocates, proponents of particular technologies, anybody who wanted to be in the process, could be in the process and so you had an expanded regulator system that led to the pursuit of a variety of things, some good some not so good depending on where you stood. Certainly more formalized planning processes something that from the beginning that I have thought always a good thing about IRM, IRP, it was more sophisticated. It required more reliance on variable outside data, all that. But it also provided a forum for people who were pursuing narrower interest to make their interest felt., and it might be almost anything.

In my part of the world in New England it was very often the environmental community they were the powerful drivers of IRP, but low income participants some times supporters of particular fuel and that leaves sometimes not just to a better regulatory process but to what economics call rent-seeking, people would pursue profit in any forum and if you can't do it in a market, you may be able to do it in an administrative form. And that's often no so good, But we've now made a critical shift over just a very few years in places like California, like Massachusetts, like Vermont, other places around the country that has decided to move toward competition. It's a critical shift much larger than the shift from rate base regulation to IRP.

This now puts markets in place of the central planning that has occurred, and so there is a lot of inconsistency, going to be a lot of inconsistency with traditional practice, reduce control by firms and regulatory, increase control by customers and for customers typically the most important factor is price. Now I mean real price here, so that the quality dimension is accounted that I won't make the explicit but you could assume I mean that when I talk about price.

People care about price, that's the main thing that I found while I was chairing Massachusetts that the people who came to us was concerned about. It doesn't mean there was a lack of interest in environmental issues that would never be the case in Massachusetts or in Maine but price matters. When people looked to the electric company, they looked to price. Well, this movement to allow broader customer choice, which arises out of the high cost situation that we found ourselves in my part of the world, that California found itself in, really does explain, I think, whey the movement toward retail competition, and frankly that's driven by economic development concerns that were acquit in those areas and in that sense perhaps it's been the larger user who has driven the process.

The regulators however, have responded in a somewhat broader fashion understanding full well that if this move toward greater competition is simply seen a way of robbing Peter to pay Paul, that is to say short changing the residential and small commercial customers for the big commercial customers that it would be not a substantial movement almost everywhere efforts are being made to have this be a broad base process and its gaining support, competition under the energy policy act, obviously at the whole sale level has moved forward. FERK with its order's 888, 889 has moved forward in providing a base, again primary at the whole sale level, but the congress is now interested in things beyond the whole sale level. You know that representative Shafer has been interested for a couple of years in the possibility of retail competition, representative **Blaily** now as well, has indicated that it would be a centerpiece for him and so we can expect I think to see some real action in this area.

I'm not sure by the way, whether the federal government really needs to get deeply involved in this like telecommunication the process is moving pretty well without the federal government, but that doesn't mean that the federal government won't move, it could easily do it anyway, as it has in telecom. But what's the end game? What does it mean? Well first and foremost choice for all customers I think in the states the focus has been on choice for all customers that's a centerpiece, not as I said a moment ago cost shifting or passing the buck, in some fashion. Now that's an idealized kind of goal, it may or may not be a realizable goal particularly in the short run. It depends in part, for example on todays rate structures and different states may tell different stories with respect to that. If the cost structure is roughly cost based (if the rate-structure is roughly cost-based) then such games across the board should be possible even though they probably won't be perportionable where there has been an extensive cross subsidy, some of that subsidy will be rung out in the process of introducing competition and so there could be losers as well as gainers it begins to get me into the story that I'm going to conclude with.

A good way to prepare for that future for regulators is to move toward more cost-based rate structures today and to allow companies more flexibility in dealing with their customers and in dealing with competition when they begin to face another core principle is functional separation of electric companies into generation, transmission and distribution. This is very remissienct of the telecommunications experience with the MFJ, where AT&T was separated into two components. One a supposedly competitive long distance component and the other was thought to be necessarily a natural monopoly component for local exchange well if you follow that area at all even just casually in the Wall Street Journal or the New York Times you'll know that that easy distinction made only little over 10 years ago has turned out to be not so easy after all and there's a good deal of reintegrated across the two units, but for that time to get the competitive process moving in long distance there was this separation and I think some of the same kind of thinking is operating here, you need to segregate what needs to be regulated from what doesn't need to be regulated. Now I said functional separation I didn't say corporate, but we will see a lot of corporate separation when things are truly functional separated, when transmission is truly made separate and independent from the companies and I think you will see that beginning to happen.

The question will be raised in management minds, "Why own this thing if I can't use it?" And I think that's the practical reason why functional separation may well go beyond that even if it's not required.

The creation of independent system operators with broad responsibility for regional transmission reliability has again independent for the electric companies and everybody else equal assess and nondiscriminatory terms and conditions for all users and probably unbundling of the services as well, I think the telecom experience is worth looking at for those who are interested in seeing where these markets are likely to go from a regulatory point of view. What kinds of short term pools and power exchanges will be created, as a basis for efficient markets is not entirely defined its been fought over in California, it was fought over in Great Britain and there are variety of mechanisms that operate in the Nordic countries in certain South American countries and elsewhere, so there is experience to draw on in designing these new competitive markets.

Regulators usually continue to give statements in favor of things like universal service building in low income protection perhaps environmental concerns will still be built into the process in some fashion but there is a lively debate on traditional regulatory involvement of PUC's in environmental issues and increased reliance on independent environmental regulation, rather than trying to merge the two as they have been in very closely merged in fact in the IRP process. Finally, the rate or return regulation which was kind of the start of a problem from an economist point of view is going to yield to performance-based regulation and price cap regulation, I think we will see the end of rate of return and rate base regulation.

Now let me talk a little bit about the transition process and then quickly turn to some activities that are going on in my two old states of Maine and Massachusetts. The first part of the transition I'm not going to say very much about although the utilities care about it very deeply and indeed so do I.

The so called stranded cost problem, dealing with historic and sunk cost, dealing with so-called uneconomic cost or even future yet to be incurred uneconomic cost is a major issue in these industries and it is my view that these must be accommodated and accounted for fairly and correctly for a variety of reasons. Not lest of which is, it would be important to do that in order to transition into an efficient well functioning market in the future this isn't just a matter of fairness, although I think there is a large fairness question there. It matters for how efficiently the new markets function, but that's not really todays audience's topic, that's why I'm going to move beyond that.

I'm going to talk about stranded benefits which is another set of activities, things that society has traditionally done using utilities as the instrument. That's the IRP process that allowed the extra points, for example for a renewable facility in order to get it into the resource mix. Or that allowed a higher level of expenditure to occur on demand side management for conservation, and so on. Those things were thought to be important and they are still issues that people are concerned about and in a completely freely functioning market, without any intervention they are unlikely to survive or at least to survive at the same levels as they have in the past.

Now let me be candid, that's not all a bad thing, but its somewhat a bad thing because some of the activities do need to be encouraged and so we need to find new mechanisms. Now I say, let me pause and explain why I made that distinction. One of the problems of the IRP process was that it did become a rent seeking opportunity. Well intentions make no mistake about it, but it did become a rent-seeking operation and with monopoly at the generation end of the market, it was quite possibly to get the regulators to agree to pass the cost of that onto customers.

Well. The customers had gotten tired of receiving those cost. But I think they still do want some of the benefits where there are real benefits, certainly that's true, in Massachusetts and in Maine, and it just happens (and this really is fortuitive), because just last week, each of those commissions, which are no longer associated with them, but still send me stuff, from time to time. And from each of them I received a rather large report. That they had completed for the legislature in each of the two states recommending methods for moving forward into the competitive electricity world, and what I want to focus on is the recommendations that have made for dealing with renewables and other kinds of desirable expenditures that the commissions respectively continue to think are important. It's important to deal with this issue up front because once there is a competitive market generation companies will not be regulated as public utilities anymore.

That is division that they will be deregulated. And where do renewable resources fit into that? What the main commission has suggested is the modest requirement that all companies selling power, within the state of Maine (obviously) have to include a minimum amount of renewable in their generation portfolio. Now they don't actually have to do it themselves the renewable requirements could be met with tradeable of credits and a commission standard of some sort will have to be set both as to the portion of the portfolio, whether it will be 2 percent or 3 percent or some number, and also what constitutes a renewable. Because in my experience that will not be obvious to everybody, it can be argued, I suppose by a pailalogologist or somebody that coal is renewable on these terms and I don't think that will happen.

Another way of going about this would be to have rate payers to simply fund through a transmission and distribution levy of some sort the monies that would be necessary to support these kinds of things, and would include by the way, advance site management, conservation and possibly low income and so on. On the renewables the portfolio kind of scheme seems like a relatively natural one. Notice that in that scheme if renewables are defined broadly and this goes to the comment that John made about staying away from selecting particular technologies, so if you define it fairly broadly then it would simply be automatically a competitive market among all within the category of revewables to try and sell to utilities so that they could meet the regulatory requirement. Now is clean coal likely to be favored in that process, probably not in Maine and Massachusetts, but certainly it is adaptable, because the rational are the same. The rational would be that its environmental beneficial in some sense and therefore deserving and perhaps in need of a boost and so therefore would be allowed to participate in this process

In Maine as I said they could generate it themselves or they could buy entitlement and that could be led to production from renewables in some entirely different location, it would not be a requirement that it happen in Maine. Massachusetts, has taken a little bid different view of this, they also wish to preserve an opportunity for renewables, they also are quite explicit in saying that it really is environmental regulators' responsibility to set the environmental regulations, not theirs. They talk about providing information on generation portfolios of different companies so that there could be a market in the purchase of environmental characteristics, from customers another element of choice and they support a mechanism where a charge is made on each kilowatt hour that is sole to create a fund that would be then made available to renewable suppliers on some basis.

I'm no longer with the commission as you know, I probably would have argued against that because I think it looks like a pot of gold which people are going to try to get their hand into and I foresee very difficult administrative process in making that work. They do argue that renewables are more subject to market failure during transmission because of their high capitol cost, higher initial investments and long payback periods I think that to is arguable it seems to me that the environmental ground is the stronger argument. The point is that when you get into a competitive world, where people can no longer do things through administration process you must do things through a separate proceeding, you must explicitly set about the task of doing whatever it is you think needs to be done that the mark doesn't do I think that has great virtual (myself).

It makes explicit what the subsidy is one of the great faults of traditional regulation is that subsidy has usually been implicit, hard to identity, hard to eliminate and quite distorting to markets, that 's the good part of moving away. Perhaps some will perceive that kind of explicit treatment, kind of sunshine treatment, as bad news because some things may not withstand, "scrutiny" when it's out in the open. But, I think we are to hope that in the kind of society that we live in that really does care about environmental issues when there are good projects, when there are good rationales for some kind of special support they will survive that scrutiny and we won't have to distort the rest of the electricity market in the process of trying to achieve those goals, that's what we're looking for, it's going to be a long hard sog. Folks, anybody who expects over night results are just kidding themselves.

One of the things I've done while pushing open markets in electricity and reliance on competition on the ground of efficiency and lower price is too in the second breath warn people that it won't come in 12 months, or 18 months or even 24 months. Some games may but the real games will only unfold as these markets precede as new generation comes on line and as we reorganize the markets in a very fundamental way. Its been going on for over 25 years in telecommunications and its not over yet, just beginning in electricity should be a very exciting time for you and I think that the coal industry will find it's place in this, the resource is too large and too efficient for it not to, but it won't happen in the ways that it has in the past.

CLEAN COAL TECHNOLOGY DEPLOYMENT: FROM TODAY INTO THE NEXT MILLENIUM

Lawrence T. Papay, Senior Vice President and General Manager
Linda K. Trocki, Manager, Advanced Technology
Ronald R. McKinsey, Manager of Advanced Fossil Power
Bechtel Technology and Consulting
San Francisco, California

I. INTRODUCTION

The Department of Energy's clean coal technology (CCT) program succeeded in developing more efficient, cleaner, coal-fired electricity options. The Department and its private partners succeeded in the demonstration of CCT--a major feat that required more than a decade of commitment between them. As with many large-scale capital developments and changes, the market can shift dramatically over the course of the development process.

The CCT program was undertaken in an era of unstable oil and gas prices, concern over acid rain, and guaranteed markets for power suppliers. Regulations, fuel prices, emergence of competing technologies, and institutional factors are all affecting the outlook for CCT deployment.

I've been asked by the organizers to identify the barriers to CCT deployment and to challenge the speakers in Panel 4 to consider how these barriers might be overcome. Below, I discuss the major barriers, and then introduce some possible means to surmount the barriers.

II. BARRIERS

The growth in the market share for clean coal technologies will be driven by institutional/regulatory structure, environmental issues, and costs (both capital and fuel).

The demand for new capacity is addressed by another panel. Bechtel's capacity addition forecasts show that 95 percent of new coal-fired capacity will be built in two of our four geographic regions--1. Europe, Africa, Middle East and East Asia and 2. Asia Pacific (Table 1). The largest markets for coal-fired capacity within these regions will be India, China, and Indonesia, with markets also in Eastern Europe, and South Africa. Only one-third of world capacity additions will be coal-fired. Natural-gas-fired capacity is expected to be the technology of choice in North and South America, as well as much of Western Europe and the Middle East.

Institutional Barriers

Deregulation

Let’s examine the institutional/regulatory issues in the US, where we’ve made the large investment in developing clean coal technologies, in the expectation that they would meet a significant need in the US.

Today, the market for new capacity additions in the US is not large. The major political factor influencing the US electricity market is deregulation. Uncertainty over the impact of deregulation on utilities is causing them to postpone many capacity additions. In addition, deregulation affects the independent power producers, while they await the impact of deregulation on issues such as future cost recovery.

Deregulation of the US market will lead to a big market shake-up during the next five to seven years. A larger number of players have entered the market in the past few years and more are likely to follow, leading to increased competition in the near-term. It will be a buyers’ market--increased competition disfavors longer-term purchase agreements. Under such market instability, suppliers won’t commit to building large coal-fired power plants (>400 MWe). Even if a supplier wishes to build one, without an assured long-term market, the supplier is unlikely to get external financing. The market outlook will certainly be too risky to use equity financing. The independent power producers have already exploited most of the desirable sites for coal-fired power plants (e.g., next to a large industrial user). Easily installed capacity in modest sizes (i.e., gas turbines) will be the technology of choice in early phases of deregulation.

In the later stages of deregulation, competition could result in large generators’ (i.e., utility) mergers, and a shake-out of IPPs, meaning there would be fewer suppliers in the market. However, technology choice might also begin to affect the market, i.e., centralization versus decentralization. For example, continued progress in “mini” turbines, fuel cells, and alike, could allow businesses, housing complexes, and even homes to have a power plant in their basement, which might be a very attractive choice if the power quality problems (expected to occur with deregulation) don’t get solved.

Deregulation is spreading. In Western Europe, the United Kingdom is privatizing their power market, and new players (such as North Sea oil and gas producers) are entering the market (although new, coal-fired power plants are still being built, as well.). The extensive deregulation occurring in the US may well spread to other OECD countries, assuming there are positive results from US deregulation.

Other Institutional Factors

In the two largest markets, India and China, institutional factors can affect capacity choices in other ways. In India, regulations are quite specific to individual states.

Building a standardized power plant in several states may be difficult, which can pose barriers to building optimized, inexpensive (i.e., standardized) CCT plants.

World Bank financing, a common source in India, can favor CCTs, by requiring that environmental factors be taken into consideration for capacity choices.

China prefers to build its own boilers and other components, which will favor cheap, simple technology, a barrier to CCT. However, outside financing and international institutions could accelerate the adoption of local regulations that would promote the use of CCT.

Growing developing country markets pose a problem to national governments as well as outside investors. Despite the rationalization of prices encouraged by development banks, there is still a tension between increasing the standard of living by providing cheap electricity versus recovering full costs in major capital investments. Perceived political risk in certain countries will also disfavor large, fixed, capital investments in one country by outside investors.

Environmental Barriers

As stated earlier, the CCT program was undertaken when acid rain was a major concern, especially with respect to burning higher sulfur coals. The clean coal program successfully demonstrated virtual elimination of precursors to acid rain. Today, global warming has emerged as a major environmental driver. Carbon dioxide is seen by the public and some of the technical community as the key component in global warming. Carbon dioxide emissions has therefore become one of the biggest technical challenge to future, environmentally-benign coal consumption .

Coal-fired electricity generation releases relatively more greenhouse gases than does combined-cycle, combustion-turbine technology (CCCT). However, the efficiency increases of CCT will decrease CO2 emissions significantly, relative to standard coal technologies, such as atmospheric fluidized bed combustors. Therefore, CCT certainly helps with the greenhouse gas problem resulting form coal consumption, but doesn’t solve it as shown in Table 2.

If the international community ever agrees upon greenhouse gas emissions quotas, the quotas could encourage use of CCT relative to conventional coal capacity, but perhaps generally discourage coal use, relative to natural gas use.

The joint implementation (JI) program is off to a rather weak start. JI could, however, subsidize CCT in developing markets, where the technology of choice might have been conventional coal technology. JI could also favor more natural gas technology, however.

Repowering and retrofitting have been proposed by many as one of the solutions to revitalize the aging US power industry. However, there are other environmental considerations that affect the market for CCT. Environmental regulations in the US discourage retrofits of coal-fired power plants. For example, retrofitting a plant makes it subject to updated emissions requirements, and also requires asbestos removal, etc. These regulations/environmental factors discourage retrofitting older coal-fired capacity with new CCT.

Cost Barriers

Table 3 shows Bechtel's projections of levelized life-cycle cost per kilowatt hour for a number of electric generating technologies. The figure demonstrates that cost poses a significant barrier to CCT adaptation, even though the cost of CCT could approach that of conventional coal-fired generation on a levelized life-cycle cost basis.

Capital Costs

The capital costs of coal technologies are at least twice the capital costs of CCCT (i.e., 2.2 to 2.9 c/kwh for coal-fired capacity compared to 1.1 c/kwh for CCCT). From a front-end investment standpoint, the cost of coal-generation certainly disfavors coal-fired capacity relative to gas-fired generation. Capital investment is also the major factor in choosing capacity type if outside financing is sought.

The near-term potential to decrease the capital cost for CCT lies in system optimization (e.g., be less conservative in redundant systems while maintaining reliability). Total system optimization can be difficult to achieve until a number of CCT plants are built, however. Even then the system optimization improvements won't halve CCT capital costs. If one expands the definition of "system" from the power plant components to a more expanded system, including fuel production, delivery, combustion, and electricity transmission, there are further economies to be captured. Whether this integrated energy system based on coal can compete with integrated systems based on natural gas remains to be seen.

The longer-term potential to decrease CCT capital costs will come from new technologies, such as ceramic membrane technology to decrease the cost of oxygen production for technologies that can benefit from an enriched oxygen source, such as IGCC. Unless we invest in these developments, however, these new technologies won't be built.

O&M Costs

O&M costs (excluding fuel) are not major differentiators for the capacity choices. The further development of "smart" operating systems are likely to further decrease the costs of running electric generators. This enhancement should benefit all technologies, but CCT, which tend to be more complex, should benefit more.

Fuel Costs

Fuel costs are relatively a much larger component of the total cost of electricity from natural-gas fired plants than they are for coal. In the absence of any decrease in capital costs, natural gas costs would have to increase significantly for a sustained period to " level the playing field" (on a levelized life-cycle cost basis) between CCCT and CCT. Natural gas costs would have to increase by about 50 percent (about $1.5 per MM Btu) relative to coal to make CCT competitive with CCCT. The natural gas price increase would have to be sustained. However, long-term natural gas price expectations generally are fairly flat. Deployment of advanced natural gas processing technologies (e.g., Fischer Tropsch) could help ensure natural gas price stability at current levels. This outlook for natural gas prices makes CCCT hard to beat on a life-cycle-cost basis, except in markets with an abundance of cheap coal and/or wastes for combustion in CCT.

III. CHALLENGES TO MARKET INTRODUCTION OF CCT

The foregoing has demonstrated the significant barriers that are presented for the widespread introduction of CCT. The question then is how does one make coal more competitive with its fossil competition? How can widespread market introduction be accomplished? This can be done by looking at the differences between coal and the alternatives and developing strategies to minimize these. The challenges below are technical ones; an alternative or complementary approach is to pursue regulatory or policy changes to effect some of the institutional barriers outlined above.

Make Coal "Look" Like Other Fossil Fuels

The variability of coal makes it difficult to take full advantage of standard plant designs (which are the cheapest). Therefore, one needs remove, as much as possible, the differences among coals of equal rank. This entails beneficiation, washing, etc. Coal blending is one method already being practiced in some cases to improve plant availability and stabilize sulfur control systems.

An additional consideration is that natural gas and oil are delivered by suppliers in an integrated manner. Therefore, we need to use an integrated, systems approach to coal preparation and delivery (mining, grinding, cleaning, transport, and the method of utilization), i.e., break apart the old "silo" approach among mining firms, transportation (railroads), and utilities/IPPs. Coal-water slurries are one example of such integration. CCT's, such as IGCC and PFBC have already demonstrated the ability to use slurries to feed coal at high pressure.

Improve Coal's Environmental Performance

The most important need here is to increase the overall efficiency of coal utilization thereby decreasing the pollutant unit per kwh or per ton of coal. As stated earlier, CCT have increased efficiency, but current initiatives by DOE, included in Combustion 2000 (and other programs) will further increase the fuel efficiency for pressurized, fluidized bed combustion, IGCC, and other CCT.

Removing coal variability as proposed above also enables more of a standardized approach to CCT. CCT is fairly flexible, for example, with minor design changes it can handle coals range from 1 to 4 percent sulfur and beyond. Further fuel flexibility could improve plant standardization.

"Blending" coal with other fossil fuels can also mitigate environmental impact. Blending can be done in a dual fuel approach or in an incremental approach as noted below. The use of natural gas in the pressurized fluidized bed topping cycle is an example of blending that improves environmental performance.

Reduce Costs on a Net Present Value (NPV) Basis

For certain technologies, we could look at how the plant can be built for dual-fuel capability in one of two ways. The first approach is to build a CCCT plant leaving space to add coal handling equipment to convert to coal as fuel prices change. The second approach is to build the plant for dual-fuel capability right from the start and mix and match as fuel prices and national interests dictate. The latter approach is a variant of the solar hybrid concept (in reverse).

Another way of improving the NPV is through environmental subsidies, i.e., recognizing that the use of indigenous fuels is desirable, but that such fuels (coal) are only competitive in the current market if environmental pressures are relaxed, a policy could be developed which would give incentives for the use of state of the art CCT. Such incentives may be provided by the Global Environment Facility, or other lending agencies involved in the country under question.

Yet another way to incrementally improve the NPV of CCT is by developing a market for the CCT with low-price fossil fuels other than coal, i.e., heavy oils, petroleum coke, orimulsion, biomass, etc. This expansion of the market for CCT could speed plant optimization. A recent announcement by GE and Toshiba that they plan to partner to market IGCC technology demonstrates this approach. Under the agreement, GE and Toshiba expect to furnish the turbine-generator equipment, and to broaden their IGCC market penetration.

IV. CONCLUSION

The implementation of clean coal technologies will be difficult for a variety of reasons as we have seen. Innovation and new approaches to commercialization, standardization, and improved environmental performance are keys to more widespread use in the next millenium.

Table 1. Regional capacity additions in gigawatts (based on orders, 1997-2002)

	Total	Natural Gas	Coal-fired	Nuclear	Hydro
North America	46	39	4	-	3
Europe, Africa, and East Asia	124	87	27	6	4
Asia Pacific	165	36	95	24	10
Latin America	57	26	2	1	28

Table 2. Relative Levels of CO2 Contributed to Greenhouse Emissions

	GTCC	PCF w/ FDG	AFBC	PFBC	IGCC	APFBC
Power, MWe	500	500	500	500	500	500
Heat Rate, BTU/kW	8030	10040	10190	8320	7940	7190
Efficiency, %	42.5%	34.0%	33.5%	41.0%	43.0%	47.5%
Fuel Heat Content, MM Btu/hr	4,015	5,020	5,095	4,160	3,970	3,595
Fuel	Nat Gas	Coal*	Coal*	Coal*	Coal*	Coal*
Heat Content, Btu/lb	23,840	13,260	13,260	13,260	13,260	13,260
Fuel Feed, lb/hr	168,410	378,580	384,240	313,730	299,400	271,120
Carbon, lb/hr	126,310	279,390	283,570	231,530	220,960	200,090
Sulfur Content, lb/hr	0	7,950	8,069	6,588	6,287	5,694
Ca/S	0	1.01	2.6	1.3		1.9
Limestone required, lb/hr	0	26,690	69,750	28,470	0	35,960
CO2 from Fuel	463,140	1,024,430	1,039,760	848,940	810,190	733,660
CO2 from Limestone	0	11,740	30,690	9,640	0	8,330
Total CO2	463,140	1,036,170	1,070,450	858,580	810,190	741,990
Normalized of AFBC	43.3%	96.8%	100.0%	80.2%	75.7%	69.3%

* Based on Pittsburgh Seam Coal

Table 3. Levelized lifecycle costs for alternative electric generating technologies

400-600 MW range

	PC (steam coal)	CCCT (nat. gas)	PFBC (waste/low grade coal)	IGCC (waste/low grade coal)
Capital c/kWh	2.2	1.1	2.6	2.9
O&M c/kWh	0.6	0.4	0.6	0.9
Fuel c/kWh	1.2-2.2	2.0-3.4	0.6-1.2	0.5-1.0
- based on deliv'd $/MMBtu range:	1.50-2.50	2.50-3.80	0.60-1.20	0.60-1.20
Total lifecycle busbar cost	**4.0-5.2**	**3.5-4.9**	**3.8-4.6**	**4.3-4.8**

1400 MW range

	LNG CCCT	Nuclear ABWR
Capital c/kWh	1.6-1.2 (2x1400 MW)	4.5-4.0 (2x1400 MW)
O&M c/kWh	0.5	1.0
Fuel c/kWh	2.5-3.3	0.6
- based on deliv'd $/MMBtu range:	3.50-4.50	0.60
Total lifecycle busbar cost	**4.2-5.4**	**5.6-6.1**

Note: The cost competitiveness of these technologies will depend for a large measure on local fuel availability and pricing. Fuel is the most widely varying cost factor for all technologies except nuclear.

REGIONAL TRENDS IN THE TAKE-UP OF CLEAN COAL TECHNOLOGIES

John M. Wootten
Vice President
Technology & Environment
Peabody Holding Company, Inc.
St. Louis, Missouri

ABSTRACT

Using surveys of the electricity industry taken in major OECD coal producing/coal consuming regions of North America, Europe, Southern Africa, and Asia/Pacific, this paper reports on the attitudes of power plant operators and developers toward clean coal technologies, the barriers to their use and the policies and measures that might be implemented, if a country or region desired to encourage greater use of clean coal technologies.

I. INTRODUCTION

The Coal Industry Advisory Board (CIAB) serves the International Energy Agency (IEA) as an advisor on issues related to the coal and electricity industries. The CIAB is made up of representatives selected by the governments of the IEA member countries. A series of three papers on industry attitudes toward clean coal technologies for power generation and the factors affecting the take-up of these technologies have been produced by the CIAB for the IEA. As a result of the information put forth in those papers, the IEA Secretariat requested the CIAB to provide its perspective on the potential for the electric power industry to take-up advanced, energy efficient, coal-fired power generation technologies (hereafter referred to as “clean coal technologies”) in the near and medium time frame. The CIAB has prepared a report, which is now under review, that presents a region by region assessment of the evolution of these energy efficient, coal-fired technologies by identifying the attitudes towards them, barriers to their take-up, and policies and measures that might be adopted to overcome these barriers. The regional assessment approach is based on the generally accepted premise that the adoption of clean coal technologies will be a function of differing technological, environmental and economic constraints from region to region. While actions on these policies and measures may involve many players, the IEA is particularly interested in CIAB’s views on those actions which governments and industry might consider.

The CIAB solicited the views of its members as well as others with electric power industry expertise within four OECD regions of the world, North America, Europe, Southern Africa and Asia/Pacific. Because the previous CIAB studies indicated that a significant amount of the growth in electric generating capacity was projected to occur in the non-OECD countries and particularly the Asia/Pacific region, the CIAB decided to devote a special effort to assessing the attitudes towards the clean coal technologies held by those independent power producers (IPP) who would most likely construct power generation facilities in the developing countries of the Asia/Pacific region. However, the results of the IPP survey are not reported here, but can be found in a paper entitled "Increasing the Efficiency of Coal-Fired Power Generation, State of the Technology: Reality and Perceptions? prepared by Shell Coal International, London, England and SEPRIL Services, Chicago, Illinois.

The clean coal technologies assessed include:

- retrofitting of enhanced controls/repowering existing plants
- the installation of advanced, more efficient steam cycle plants as described in Industry Attitudes To Steam Cycle Clean Coal Technologies, Survey of Current Status (OECD/IEA 1995)
- the development and commercial application of combined cycle technologies as described in Industry Attitudes To Combined Cycle Clean Coal Technologies Survey of Current Status (OECD/IEA 1994)

Again, because the Asia/Pacific region is projected to experience a significant increase in the amount of electric power generating capacity and the technology that is expected to be utilized most often is conventional subcritical pulverized fuel (PF) technology, the CIAB decided to contrast the capital costs, operation and maintenance expenses, reliability of operation and environmental emission characteristics for the conventional PF technology with those of one commercially available clean coal technology, supercritical PF. These results can also be found with the IPP survey results referenced above.

As was deemed appropriate for each region the assessments include:

- consideration of the growth in the demand for electricity in the region and the corresponding generating capacity that will supply that demand segregated by fuel type and technology to the extent possible.
- consideration of the degree of take-up of the clean coal technologies before 2015.
- consideration of likely relative capital costs and the effect on the price of electricity from the clean coal technologies, compared with existing technologies (e.g. taking into account the higher rates of return on investment required to compensate for the perceived extra risk).

- consideration of any extra environmental advantages of the newer technologies. This consideration would need to consider the possibility of the development of more stringent future environmental standards within the region.
- identification of government and private-sector policies, measures and incentives that would enhance the adoption of the clean coal technologies.

This paper summarizes the results of the regional assessments.

II REGIONAL ASSESSMENTS

The attitudes of power generators, both utility and independent power producers, towards the clean coal technologies is expected to be different from region to region because attitudes are influenced by differing technological, environmental and economic constraints. The following discussion is an assessment of these differing attitudes and their implications on the take-up of the clean coal technologies in each region.

OECD North America

Regional attitudes in North America were assessed by examining Canada and the United States.

Canada

The attitudes of the Canadian utility industry towards the take-up of the clean coal technologies is taken from a report entitled "The Potential for Energy Efficient Coal-Fired Power Generation in Canada", prepared by Edmonton Power. This assessment is a compilation of responses from utilities in Canada which collectively represents almost 97% of Canada's electricity generation and all existing coal-fired generation.

Canada is extremely large geographically and, therefore, a diverse nation in many respects, not the least of all in electricity generation. Coal, natural gas and hydro power are readily abundant depending on the Province in question. Nuclear power has been developed extensively in Eastern Canada. Since 1980, new generating capacity has been installed in all parts of the country embracing all "conventional" technologies" with hydro, nuclear and subcritical PF being the dominant technologies. Only one advanced technology has been installed during this period, a 182 MW AFBC unit in Nova Scotia during 1995.

Generating capacity is forecasted to increase 2.8% by 2000 with further increases of 3.0%, 4.3% and 3.4% respectively in each 5-year block until 2015. This represents a modest annual growth rate of 0.68%, while energy consumption is expected to increase by 1.38% per year until 2015. Of the new capacity being added, 15.9% is expected to be coal-fired and 49.8% is expected to rely on natural gas. Repowering with the addition of a gas turbine and life extension with improved unit efficiency will also play major roles in fulfilling new capacity requirements.

In choosing the types of new capacity, capital and fuel costs were cited as the top two determining factors, followed by environmental considerations, plant availability, return on capital invested, construction time, and security of fuel supply. In those Provinces where deregulation is occurring, the higher risk of not recovering costs makes the reduction of investment risk through shorter planning, design and construction times a key factor. CO2 is considered the most important environmental factor, followed by SO2, NOx and siting considerations.

The potential for the take-up of the clean coal technologies in Canada is relatively low with the limited addition of coal based capacity. The expressed interest is in IGCC technology to be installed after 2006. Interest in the other technologies will be dependent on their commercial maturity and economics in the same time frame.

The barriers to the clean coal technologies are increased deregulation of the electric industry with the delay of long-term decisions due to uncertainty, increasing environmental limitations and costs associated with coal-fired technologies, increasing complexity of financing arrangements and in a deregulated market, gas will be very competitive with coal.

In those locations where gas is readily available and competitively priced, it will act as a barrier to the take-up of clean coal technologies. In addition, proof of performance in the areas of environment, reliability, operability and power cost at a commercial scale in a utility environment is needed. Similarly, the capital cost and construction time of the clean coal technologies must be reduced. Proposals under consideration to control/tax greenhouse gases are seen as limiting the opportunities for coal based technologies.

Government policies to overcome these barriers should address two areas; funding a substantial portion of up-front R&D and demonstrations consistent with long-term environmental policies and favorable tax/depreciation for environmentally sound technologies requiring penetration assistance.

United States

The attitudes of electricity producers in the US towards the take-up of advanced energy efficient, coal-fired technologies is assessed in the report entitled “Regional Trends in the Evolution of Energy Efficient, Coal-Fired Power Generation Technologies in the United

States", Prepared by Peabody Holding Company, Inc. The assessment is based on published information which reports the results of surveys of electric utilities and independent power producers attitudes towards clean coal technologies. Since 1986 the US Department of Energy (DOE) has been administering a government/industry co-funded program to demonstrate clean coal technologies at a utility scale. The Clean Coal Technology (CCT) program has resulted in a US $6.9 billion effort for the first-of-a-kind or early commercial demonstration of the clean coal technologies that the CIAB has previously reported to the OECD/IEA. The attitudes reported here are influenced by the experiences learned in the CCT program.

Kilowatt hour sales in the US are expected to increase by 31% for the period 1995 to 2015. During that same period net generating capacity additions are expected to increase by 22% or 167 gigawatts (GW). New capacity additions plus replacement capacity for retired units is expected to be 252 GW. Coal-fired capacity additions are projected to increase by 5% or 15 GW. Natural gas-fired capacity will dominate with a 69% increase or 166 GW while nuclear capacity will decrease by 36% or 35 GW. The majority of the nuclear reductions are projected to occur after 2010 when most of the plants' current licenses expire. The projections do not reflect any changes that may occur as a result of the deregulation of the US electric industry.

The potential for the take-up of the clean coal technologies exists in the 252 GW of new or replacement capacity. However, this potential is influenced by a number of attitudes of the user community. The opportunities for base load units are limited before 2000 and increase to some extent between 2000 and 2005. The clean coal technologies are viewed as having higher capital and operating costs relative to subcritical PF technology. Subcritical PF appears to be the coal technology of choice despite the fact that supercritical PF is viewed as a proven, reliable technology. IGCC is viewed as somewhat proven/reliable, while PFBC is viewed as not proven. Strong interest exists in life-extension and improving performance at existing plants. In addition, deregulation is delaying, indefinitely, long-term decisions for additional generating capacity.

The barriers identified to the take-up of the clean coal technologies are many. Coal continues to a have a poor public and political image even though the clean coal technologies offer the promise of significant efficiency improvements and reduced environmental impact. Coal remains the fuel-of-choice for base load applications. Where natural gas is readily available and competitively priced, natural gas will continue as the fuel-of-choice for incremental capacity additions. Concern exists over the future regulation of CO2. Life cycle costs are less important and decisions are being driven by short-term considerations related to financial risk.

Policies and measures that could be implemented center around two areas - technology transfer and economic incentives. The attitudes of the electric utility industry indicated a lack of knowledge and perhaps an excessive degree of risk aversion concerning the commercial status, costs and reliability of the clean coal technologies and, in particular, supercritical PF. A better job needs to be done to market the clean coal technologies by providing more information on risks and costs. This program should be targeted at non-utility generators because of their future role in providing new capacity additions. Finally, without some program of cost sharing to reduce risk, the clean coal technologies are unlikely to be taken-up to any significant extent before 2005. Financial incentives that have been explored are subsidies and special tax/depreciation treatment.

OECD Europe

In Europe, the attitudes of 16 OECD member countries were solicited and the findings are contained in the report entitled “Regional Studies on Evolution of Power Generation, OECD Europe”, S-K Power, Denmark. Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Netherlands, Norway, Spain and the UK responded to the request for information and these 13 countries represent OECD Europe for purposes of this paper. In addition, information was requested for the 20 year period 1995 through 2015. However, not all respondents were willing to provide information for the 2010-2015 timeframe and those that did respond, had strong reservations about the reliability of the data. Therefore, the time frame for OECD Europe information is 1995 through 2010.

The OECD Europe electric power industry expects a fairly constant load growth over the period from 1995-2010, to the order of some 16% growth in capacity and a higher 27% growth in energy use.

As a consequence of the on-going transition of the industry from one of monopolies to a deregulated competitive market, power companies have redefined their earlier strategic/politically based objectives (technological reliability/availability, fuel flexibility and use of indigenous fuels) to economic ones like return on investment and capital cost. At the same time, environmental considerations are expected to continue to play an important role in the future choice of generating capacity.

European power companies expect oil to lose ground as an energy source in Europe over the next 15 years; while coal and nuclear should maintain the status quo; and hydropower should see a small increase. Capacity based on renewable fuels will enjoy a large increase, but even so, it will remain an incremental energy source.

Natural gas fired technologies with their relatively low capital costs and environmentally friendly image will supply most of the growth. This is remarkable because even though most European power companies agree that “Europe is becoming too dependent on imported natural gas”, they still plan to select natural gas as their fuel for new capacity.

In comparison to gas, the expectation for the installation of new coal based capacity is low. Coal-fired capacity, that will be built over the next 10 years, will be supercritical PF technology. After 2005, the choice of clean coal technologies will be dependent on their state of development at that time.

The main barriers to the enhanced take-up of the clean coal technologies are economic in nature (e.g. high capital costs) and except for countries already hosting demonstrations of clean coal technologies, a skeptical view of the maturity of the PFBC and IGCC exists. Furthermore, coal has a public/political image problem.

Various proposals have been put forward by the power companies to overcome the barriers to the take-up of the clean coal technologies. As regards high capital costs, suggestions include political support of the continued development and dissemination of the clean coal technologies through subsidies, financing or funding. Preferential treatment in the market place of the electrical output from the clean coal technologies is another possible approach.

When it comes to overcoming the skepticism on the maturity of PFBC and IGCC technologies, the fact that countries hosting the technologies have a strong confidence in their virtues could indicate that a better dissemination of demonstration plant locations could constitute an effective way of proving their commercial readiness to a broader audience.

Finally, proposals to overcome environmental (including public and political image problems) barriers entail providing more information on the virtues of coal as a fuel, e.g. the large and geographically widespread resource base and the advanced technological state of today's coal mining and coal usage facilities. Further, the implementation of closed handling systems at harbors and power plants might be beneficial to coal's image.

Southern Africa

The Southern Africa assessment presents the views of developing countries whose primary emphasis is regional development and the role that power generation plays in that development. Limited information is presented for 15 sub-Saharan Africa countries and detail information is presented for South Africa in the report entitled "Evolution of Power Generation, Southern Africa Study", prepared by the ESKOM Technology Group. During 1995, South Africa accounted for 76% of the generating capacity for the region and produced 83% of the electrical generation. As a result the regional information is to be considered quantitative at best.

The perspective from the Southern Africa region is fundamentally different than for developed OECD countries. Development is focused on local and regional issues and attempts to maximize international cooperation to ensure that development is optimized. This entails securing clean coal technologies during development with the incremental costs above conventional technology being borne by the developed countries. This approach has been referred to as "Activities Implemented Jointly" in the context of reducing environmental impacts.

The 1995 electricity supply and demand situation for the 16 sub-Saharan African countries is one of significant over supply. The region has a total of 46 GW of installed capacity and electricity production totaled 207,545 GWh which represents 52% of the potential production. Under current projections, it is unlikely that additional capacity will be required in the region before the year 2010. Excess capacity in the region may be optimally utilized via the Southern African Power Pool. However, issues such as the reliability of long transmission lines, coupled with individual national priorities could result in additional capacity being built before 2010. Any increase in capacity will, in all likelihood, be met predominately by coal in South Africa and by hydro in the other countries in the region. In addition, South Africa has introduced a demand side management program as an alternative to capacity additions.

In spite of the over supply situation and because future growth is highly uncertain, supply side options are being evaluated for future applications. Clean coal technologies are being evaluated with the objective of reducing lead time, capital and operating costs, environmental impacts and optimizing unit size and load following capability. Environmental impacts focus on local and regional impacts with a lower priority on global impacts.

Clearly the most significant barrier to the take-up of clean coal technologies in Southern Africa is the excess of generating capacity which is expected to exist until after 2010. Other potential barriers include: perceptions of unreliability and higher operating costs, limited local skills and infrastructure, competition from other fuels such as hydro, gas and possibly nuclear. Also the existing capacity is relatively new (11-15 years) and retirement and replacement with clean coal technologies has a low potential.

Realizing that capacity is not needed in Southern Africa till after 2010, options open to both governments and industry to overcome the barriers from a developing nations point of view include means to catalyze economic growth, funding of the premium for the installation of clean coal technologies by the developed nations, demonstrations in developing countries, a robust program for disseminating information on the technologies and development of human capabilities in developing countries.

OECD Asia/Pacific

The assessment of the OECD Asia/Pacific region consists of a compilation of attitudes in three countries: Australia, New Zealand and Japan.

Australia/New Zealand

Australia and New Zealand constitute a region of the world where government has recently promoted competition in the electric power industry. This has developed an opportunistic approach and less certainty in the type and timing of new generation plant additions. The assessment of the take-up of clean coal technologies reflects this change in the electric industry and is presented in detail in the report entitled “Regional Studies On Evolution Of Power Generation Australia and New Zealand”, prepared by Sligar and Associates Pty. Ltd., New South Wales, Australia on behalf of CRA Limited.

Load growth in Australia and New Zealand is expected to average 2% per year through 2015. This low predicted growth, coupled with existing reserve margin in some areas and the developing highly competitive situation, will lead to new generation initiatives in the near future. New generation will be incremental in nature and with the deregulation of the Australian gas industry will favor gas as the fuel-of-choice. A major portion of the coal capacity has recently been retrofitted and further refits are scheduled before 2000. The retrofits consist of minor technology advances and it is unlikely that these refits will employ any clean coal technology, e.g. IGCC.

Before deregulation, the energy mix was under the control of the two countries’ governments, but now the competitive market will dictate the mix of capacity additions. In this competitive environment, organizations are somewhat reluctant to release their capacity addition plans, but an estimate of minimum likely new generation has been made based on a number of sources and statements in interviews. Likely new generation in Australia is projected to total 16.6 GW by 2015 with 2.2 GW coal, 6.8 GW gas, 5.6 GW renewables, and 2 GW uncommitted. There is 1.5 GW of gas generation available in eastern Australia and 1.0 GW in western Australia which is expected to be utilized by 2000. Installation of gas-fired generation after 2000 will depend on the discovery and development of the production and transmission systems. The likely installation of a new generating plant in New Zealand by 2015 will total 1.7 GW with 0.6 GW gas, 0.4 GW renewables, and 0.7 GW of uncommitted.

Attitudes towards the clean coal technologies in Australia and New Zealand are dominated by the competitive market place and, as a result, clean coal technologies are not under active consideration in either country. However, if that situation were to change, existing and potential generators would evaluate the clean coal technologies using the following factors in their order of importance: required return on investment, environmental and political considerations, and capital costs. Under environmental factors, CO2, then NOx, SO2 and others are the emissions of concern in their order of importance. Where coal technology is under consideration for new capacity, subcritical PF is the technology of choice through 2000. IGCC is projected to be introduced beginning in 2005 and it will become the preferred alternative by 2010. AFBC and PFBC are thought to have limited application.

The barriers to the take-up of the clean coal technologies in Australia and New Zealand are again a direct result of the competitive situation in the electricity industry and can be divided into competition/economic and technical issues. The competitive/economic barriers center on whether the clean coal technologies can provide an acceptable return on investment, competitive capital costs, reduced construction period, and be competitive with gas-fired generation. On the technical side, barriers such as unit size greater than 500

MW, proven reliability, and a lack of information on the technical and cost characteristics are the primary issues. In some instances, existing or new generators had a limited understanding of the attributes of the clean coal technologies.

Beyond the competitive/economic issues, the environment also has a strong influence on the take-up of new technology. The environmental anti-coal lobby is becoming a growing force that must be considered. In addition, there are low cost CO2 mitigation strategies that will be considered before coal-fired technologies.

Consideration of policies and measures to overcome the barriers to the take-up of the clean coal technologies is not a well developed concept in Australia and New Zealand because the clean coal technologies are not under active consideration. In keeping with that situation, there appears to be a limited base of knowledge about the clean coal technologies that needs to be addressed by a better dissemination of pertinent information.

Japan

The assessment for Japan is taken from yearly reports to the Ministry of International Trade and Industry (MITI) prepared by the 10 regional electric utilities. Data on regional demand and demand growth is reported and organized by fuel type. Information concerning the take-up of the clean coal technologies was provided by both major equipment suppliers and the regional utilities. This information has been compiled into a report entitled "Study on Evolution of Energy-Efficient, Coal-Fired Generating Technology (Regional Studies Asia-Pacific)", prepared by the Electric Power Development Company.

The expansion of electricity generation installed capacity will continue to be driven, at least until the beginning of the 21st century, by the concept of diversification of the fuel mix to increase the security of supply. Power generation capacity in Japan is expected to increase by 101 GW through 2010. During the period 1996 through 2005, 70.7 GW of capacity will be added with 10.1 GW hydro, 21.7 GW coal, 26.5 GW LNG plus LPG, 0.4 GW of Orimulsion, 0.1 GW of geothermal and 14.6 GW of nuclear At the same time oil and other gas capacity will decrease by 2.0 GW.

Clean coal technologies will play a major role in the coal-fired capacity being planned. Ultra supercritical steam cycle (USC) technology and PFBC will play a major role in the new coal-fired capacity additions. Candidate projects, so dubbed because all details of the installations have not been finalized, account for 4.6 GW of capacity, 4.1 GW USC and 0.5 GW of PFBC. Japan currently has 16.6 GW of supercritical and USC and 400 MW of AFBC capacity operating in the country as well as a 70 MW PFBC unit. Two additional 350 MW PFBC units are in the planning stage.

Environmental regulation in Japan is becoming more and more severe. Citizen groups are taking a more active role in shaping agreements between the local authorities and the utilities. In some situations power plants have had to install a dry flue gas desulfurization system based on scrubbing with activated char. This advanced emission control system has similar capital costs to FGD and SCR but has higher operating costs due to the activated char.

The Japanese Government has supported the take-up of the advanced flue gas desulfurization and selective catalytic reduction technologies, so far, by establishing a shorter depreciation period of 7 years as opposed to the normal 15 years. In addition, MITI often provides financial support for the demonstration of the clean coal technologies. However, recent moves to deregulate the electricity industry in Japan constitutes a new barrier to clean coal technologies in Japan. As a result, the cost factor and increased competition is causing the utilities to become more conservative in their choice of clean coal technologies and less able to accept long-term returns.

IV. CONCLUSIONS

The following discussion presents specific conclusions from the regional assessments:

OECD North America

- Growth in generating capacity in the region until 2015 is projected to be 204 GW with 21 GW of coal-fired capacity.
- The attitude towards the clean coal technologies is shaped by the following factors:
    - deregulation is delaying long-term decisions on capacity.
    - little need for base load capacity.
    - capital costs, reliability, fuel costs and environmental constraints are key criteria for selecting technology for new capacity additions.
- Barriers to the take-up of the clean coal technologies are:
    - increased availability of natural gas and relatively lower capital costs for natural-gas fired technologies.
    - high capital costs of PFBC and IGCC.
    - lack of commercially demonstrated reliability and operability.
    - lack of awareness of attributes by potential developers.
- Policies and measures that could overcome the barriers are:
    - change negative attitude of government and public towards coal.
    - provide financial and regulatory incentives, e.g. tax relief, specialized depreciation, financial support, and permitting relief for the early commercial applications (first 3 to 5 installations).
    - implement a program to inform IPP’s and other developers on the virtues of the clean coal technologies.

OECD Europe

- Growth in generating capacity in the region until 2015 is projected to be 82 GW with 1 GW of coal-fired capacity.
- The attitude towards the clean coal technologies is shaped by the following factors:
  - deregulation has redefined priorities from reliability/availability to economic.
  - environmental limitations remain a strong consideration.
  - natural gas appears to have advantages in some countries where it is available and competitively priced.
  - countries with demonstration projects have a higher confidence in the clean coal technologies.
  - supercritical PF viewed as a proven technology in some countries.
- Barriers to the take-up of the clean coal technologies are:
  - low capital costs of natural gas-fired technologies.
  - opportunity for the installation of base-load coal-fired capacity negligible.
  - economic competitiveness in question.
  - uncertainty of commercial status and reliability of PFBC and IGCC.
- Policies and measures that could overcome the barriers are:
  - reduce capital cost through favorable financial incentives.
  - harmonize emission limits and energy taxes.
  - virtues of coal should be publicized.
  - conduct pilot/demonstration projects in more countries.

Southern Africa

- Growth in generating capacity in the region until 2015 is projected to be 24 GW with 18 GW of coal-fired capacity.
- The attitude towards the clean coal technologies is shaped by the following factors:
  - local and regional development takes precedent over technology choices.
  - coal and hydro are the preferred choices when capacity is required.
  - clean coal technologies are viewed favorably, but must be proven against competing options on a cost, availability and reliability basis.

- Barriers to the take-up of the clean coal technologies are:
  - no generating capacity required until after 2010.
  - existing capacity is relatively new.
  - hydro focus in the region.
  - perception is of high operating costs.
  - limited worker skills and supporting infrastructure.
  - deregulation and competition defer decisions and increase risk avoidance.

- demonstration of acceptable environmental performance on local coal.

- Policies and measures that could overcome the barriers are:
  - catalyze economic growth.
  - apply joint implementation/activities implemented jointly provisions of the UN FCCC.
  - increase the communication of RD&D technology information.
  - improve costs, availability and reliability.
  - direct government intervention, e.g. financial incentives.

OECD Asia/Pacific

- Growth in generating capacity in the region until 2015 is projected to be 303 GW with 45 GW of coal-fired capacity and 43 GW of that installed in Japan.
- The attitude towards the clean coal technologies is shaped by the following factors:
  - deregulation/competition is becoming a significant factor in capacity choices.
  - environmental limitations are important.
  - Japan's capacity choices driven by national goal of diversification of fuel mix to increase the security of supply.
  - return on investment, environmental, politics and capital cost drive capacity decisions.
- Barriers to the take-up of the clean coal technologies are:
  - deregulation/competition in electricity industry.
  - lack of proven availability and financial risk at unit sizes greater than 500 MW.
  - trend toward cost cutting.
- Policies and measures that could over come the barriers are:
  - government financial incentives.
  - encourage market competition between technologies.
  - better methods for disseminating information.

V. REFERENCES

Regional Trends in the Evolution of Energy Efficient, Coal-Fired Power Generation Technologies, Coal Industry Advisory Board to the IEA, Paris, France, 2nd Draft October 1996.

INTERNATIONAL ENERGY AGENCY
COAL INDUSTRY ADVISORY BOARD

INDUSTRY PERSPECTIVES ON INCREASING THE EFFICIENCY OF COAL-FIRED POWER GENERATION

Ian M. Torrens & **William C. Stenzel**
Shell Coal International **SEPRIL Services**

ABSTRACT

Independent power producers will build a substantial fraction of expected new coal-fired power generation in developing countries over the coming decades. To reduce perceived risk and obtain financing for their projects, they are currently building and plan to continue to build subcritical coal-fired plants with generating efficiency below 40%. Up-to-date engineering assessment leads to the conclusion that supercritical generating technology, capable of efficiencies of up to 45%, can produce electricity at a lower total cost than conventional plants. If such plants were built in Asia over the coming decades, the savings in carbon dioxide emissions over their lifetime would be measured in billions of tons.

IPPs perceive supercritical technology as riskier and higher cost than conventional technology. The truth needs to be confirmed by discussions with additional experienced power engineering companies. Better communication among the interested parties could help to overcome the IPP perception issue. Governments working together with industry might be able to identify creative financing arrangements which can encourage the use of more efficient pulverised clean coal technologies, while awaiting the commercialisation of advanced clean-coal technologies like gasification combined cycle and pressurised fluidised bed combustion.

EXECUTIVE SUMMARY

- New generating capacity required globally between 1993 and 2010 is estimated to be around 1500 GW, of which some two-thirds will be outside the OECD, and some 40% in the Asian non-OECD countries. Coal is likely to account for a substantial fraction of this new generation, and with liberalisation of electric power markets driven by the need for inward investment, independent power producers are likely to build a substantial number of the coal-fired power plants in developing countries.

- Today's state-of-the-art supercritical coal-fired power plant has a conversion efficiency of some 42-45%, about 5 percentage points higher than that of the conventional subcritical plants which continue to be built in most projects in non-OECD countries. If supercritical plants were to be built instead, the amount of incremental carbon dioxide not released to the atmosphere over the next few decades as a result of electricity generation would be measured in the billions of tons, without constraint on energy and economic growth. Depending on the generating efficiencies achieved, the CO2 emission reductions over the lifetime of the plants built during one decade of growth in Asia alone could amount to 5-10 billion tons.

- With more than 350 supercritical units operating world-wide today, and more than two decades of experience and development of this technology, their reliability today is assessed by authoritative observers and operators of power plants to be at least as good as that of conventional sub-critical plants.

- A new engineering assessment by an international power engineering firm concludes that the capital cost increase associated with a supercritical or ultra-supercritical pulverised coal power plant compared to a conventional subcritical plant is small to negligible. The reason is that capital cost increases specific to the supercritical plant (e.g. associated with superior materials and other design features) are counter-balanced by the capital cost savings associated with the fact that the boiler and ancillary equipment can be smaller due to the increased efficiency.

- The increased efficiency associated with the supercritical plant leads to an actual reduction in the total cost of electricity generated in cents/kWh, relative to a conventional plant. In fact, depending on fuel price, an ultra-supercritical plant with flue gas desulphurisation, selective catalytic reduction for post-combustion NOx control, and a high efficiency baghouse for particulate control, can produce marginally cheaper electricity than a conventional subcritical plant with only an electrostatic precipitator for particulate control.

- Despite this, the independent power sector continues to build subcritical plants and has no near-term plans to increase the efficiency of power plants in the projects it is developing. There is a clear perception among IPP companies that supercritical technologies are both more expensive and contain more risk than subcritical technologies. Part of the reason for this appears to be innate conservatism among their technology suppliers and project financiers.

- IPP companies' decision-making is driven primarily by the issues of reliability, technology cost, government regulation, and lender attitudes or financing constraints. Generating efficiency is perceived to be of second-order importance.

- Advanced clean coal technologies such as integrated gasification combined cycle and pressurised fluidised bed combustion will be selected for independent power projects only in very specific circumstances, where their technology and other risks are fully covered and their incremental costs are recovered in the price of electricity. Market penetration on a wider scale is seen by the IPPs as being in the 2005-2010 timeframe or beyond.

- It appears that the only way to accelerate this is to complete a number of successful demonstrations which, in particular, show that advanced clean coal plants can be operated reliably and with superior performance, and specifically that their present estimated capital costs can be reduced substantially to a point where they are competitive with state-of-the-art pulverised coal technologies. These second- or third-of-a-kind demonstrations are likely to require financial support by governments if they are to be realised.

I. INTRODUCTION

The CIAB's Global Climate Committee was asked by the IEA to assess the evolution of energy-efficient coal-fired power generation in non-OECD countries.. The primary market for coal over the coming decades will be electricity generation, especially in the newly industrialising countries of the developing world. Estimates of the amount of new generation required between 1993 and 2010 are in the region of 1500 GW, of which more than 700 GW are in the non-OECD countries (Figures 1, 2). Coal is expected to account for a large proportion of new electricity generation (Figure 3).

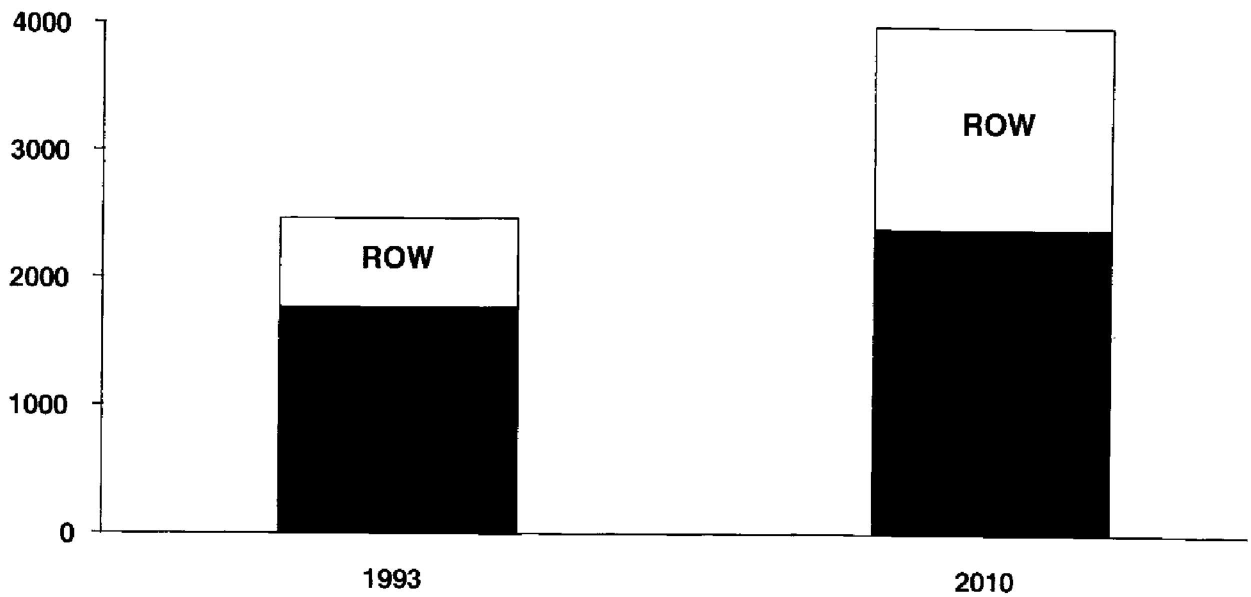
The global issues of sustainable development and the enhanced greenhouse effect are topics of importance to IEA Member governments and CIAB members. Coal, as a fossil fuel with a reserve base measured in centuries rather than decades, is an important part of the global economic-energy-environment equation. It is clear that for the newly industrialising economies to sustain the major growth phase now in progress, coal must play its part as an efficient and environmentally sound source of energy.

Today's state-of-the-art supercritical pulverised coal-fired power plant has a conversion efficiency of some 42-45% (lower heating value - LHV), about 5 percentage points higher than that of the conventional subcritical plants which continue to be built in most projects in non-OECD countries. The main question addressed by this paper is, what would be needed to have state-of-the-art technology accepted for new power projects in these countries? If this were achieved, the amount of incremental carbon dioxide not released to the atmosphere over the next few decades as a result of electricity generation would be measured in the billions of tons, without constraint on energy and economic growth.

The necessary growth of electricity generation capacity in the industrialising countries will require very substantial inward investment. In order to attract this investment, generation of electricity is

Figure 1

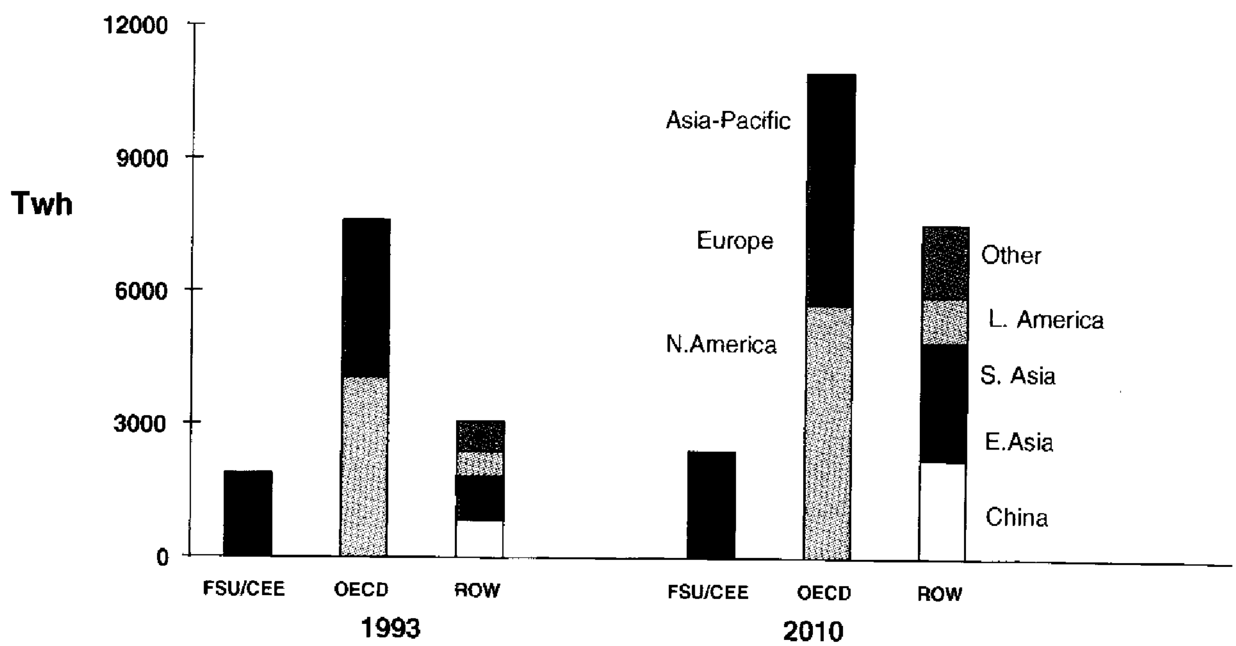
Electricity Generating Capacity Growth (GW)
1993 - 2010



Source : IEA World Energy Outlook 1996

Figure 2

Electricity Output by Country/Region(TWh)
1993 - 2010

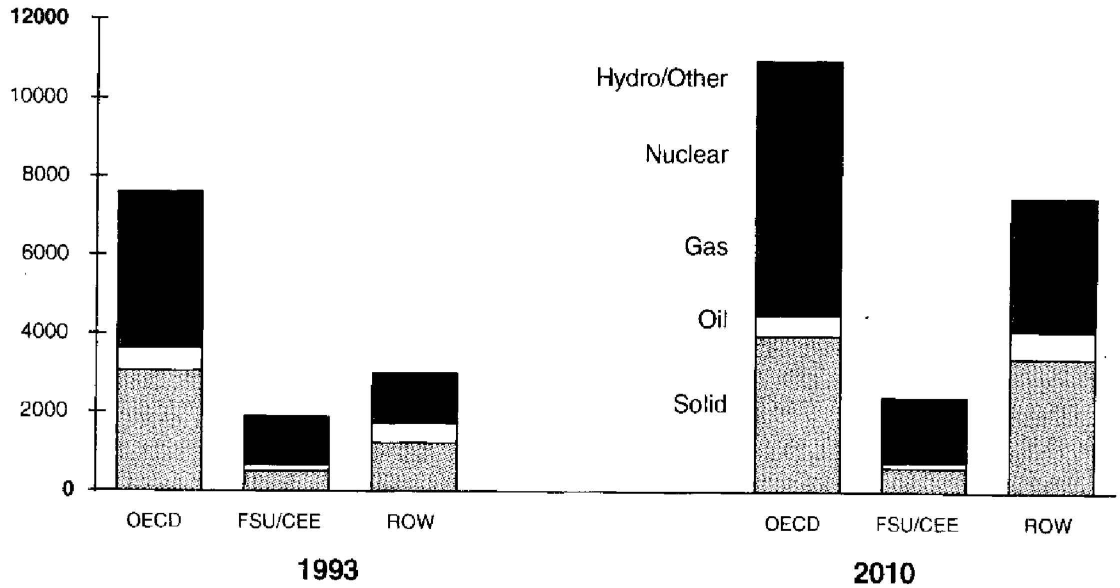


Source : IEA World Energy Outlook 1996

Figure 3

Primary Energy Shares in Power Generation (TWh)

1993 - 2010



Source : IEA World Energy Outlook 1996

being privatised in an increasing number of countries. The involvement of independent power producers (IPPs) in private power projects in a number of countries is an important part of this process.

The CIAB took a two-pronged approach to the issues related to improving generating efficiency in new coal power generation in non-OECD countries. A consultant, SEPRIL, jointly owned by the Electric Power Research Institute and Sargent & Lundy), was engaged to provide an analysis of costs and other issues in the comparison of subcritical, supercritical and ultra-supercritical pulverised coal plants in these countries. At the same time, in order to benefit from the insights which IPPs have gathered as a result of their experience to date in private power projects and business development in newly industrialising countries, the CIAB designed a relatively simple survey by telephone interview. The most appropriate people to respond to such a survey were identified and the interviews carried out between April and July 1996.

The results of the IPP Survey are summarised in the next Section. The findings of the cost and performance comparative analysis are presented in Section III.

II. OVERALL SUMMARY OF SURVEY RESULTS

A total of fourteen companies took part in telephone interviews and/or provided written responses to the CIAB Questionnaire. The companies taking part in the Survey were:

ABB Carbon	AES Corporation
Babcock and Wilcox	Black and Veatch
Community Energy Alternatives	CMS Generation
Duke Energy	Edison Mission Energy
Elsamprojekt	Entergy Power Systems
IVO Energy International	National Power
NRG Energy	Southern Electric International

The majority of those interviewed represented independent power producing companies involved in developing power projects in non-OECD countries. However, representatives of several power engineering/construction companies and technology suppliers also participated. Those who agreed to take part in the Survey were assured that the anonymity of their responses would be protected, and that the results of the Survey would be shared with them as soon as possible.

There was a high degree of consensus among the participants in their response to the questions, which makes it relatively simple to draw broad conclusions. The main lessons to be drawn from the Survey are the following:

1. Technologies used or foreseen

The vast majority of projects use or plan to use sub-critical pulverised coal technologies for larger plants, with some smaller projects using atmospheric fluidised bed combustion (AFBC) technology. Supercritical pulverised coal technology is viewed as technically commercialised but riskier and more costly, and needing incentives such as high priced fuel to be the technology of choice. Pressurised fluidised bed combustion (PFBC) and integrated coal gasification combined cycle (IGCC) technologies may be used in special circumstances (e.g. government support) in the coming years, but are unlikely to come into widespread use by IPPs until 2005-2010 or beyond.

2. Environmental Requirements

The World Bank Environmental Guidelines play a major and increasing role in most countries. Most IPPs and developing countries are aware of a 1995 draft of these which is stricter than the 1988 official version, and believe these new guidelines will be implemented shortly. Some IPPs have corporate environmental guidelines which go beyond the World Bank ones; however, to go too far beyond raises economic competitiveness issues.

3. Main Factors influencing Technology Selection

The results of a poll included in the Survey, on the principal factors influencing technology selection and their relative importance in decision-making, are shown in Table 1 below.

TABLE 1

CIAB IPP Survey Responses

Impact of Different Factors on Coal Power Generation Technology Selection

1 = Not important 5 = Extremely important

Response No.	1	2	3	4	5	6	7	8	9	10	11	12	14	15	Mean	S.D.
Environment	4	4	3	4	2	4	5	3	4	3.5	4	4	5	5	3.9	0.83
Efficiency	4	3	3	4	2	3	4	3	5	4.5	3	5	4	3	3.7	0.9
Reliability	4	4	4	5	5	5	4.5	5	5	5	3	5	4.5	5	4.6	0.6
Maintainability	3	5	4	5	4	5	4	5	4	4	3	4	4	5	4.2	0.68
Technology Cost	5	5	5	4	4	5	5	4	5	5	5	4	3.5	5	4.6	0.55
Technology Maturity	3	4	4	4	5	3	4	4	4	4	4	5	3	5	4	0.65
Technology Risk	3	4	4	5	5	3	3	4	4	4	4	4	5	5	4.1	0.7
Build Time	4.5	4	3	4	3	3	3	3	5	4	3	4	3	3	3.6	0.78
Fuel Flexibility	2.5	4	2	4	2	3	5	3	3	3	3	5	5	2	3.3	1.07
Operational Flexibility	3	3	3	4	2	3	3	3	4	3.5	3	4	3	3	3.2	0.56
Need for Skilled Operators	3	4	1	3	3	4	3	3	3	3.5	3	4	3	5	3.3	0.88
Customer Specifications	4	5	5	4	5	2	3	3	4	4	3	4	3	3	3.7	0.88
Financing Constraints	4.5	5	4	4	3	5	5	4	5	5	4	5	5	5	4.6	0.62
Lender Attitudes	4	4	3	4	4	4	5	4	4	4	4	5	5	3	4.1	0.59
Government Regulation	3.5	4	5	5	4	5	5	4	5	5	4	5	5	1	4.4	1.08

S.D. = Standard Deviation

Reliability, technology cost, and financing constraints were voted the most important factors (averaging 4.6 on a scale of 1 to 5 in importance). The standard deviation in the responses was relatively small, of the order of 0.6, indicating a strong consensus on these factors. The next most important factors were government regulation (4.4), maintainability (4.2), technology risk and lender attitudes (both 4.1), technology maturity (4.0), and environment (3.9). Interestingly, the need for skilled operators scored relatively low in the poll (3.3), the IPP view being that it is relatively easy to find and train operators.

4. Power Plant Conversion Efficiencies

Most coal-fired power plants being planned or built today use sub-critical technology and have conversion efficiencies in the range of 37-39% on a lower heating value (LHV) basis (9200-8700 Btu/kWh). Responses on future trends in efficiency over the next 5-10 years were mixed, though few expect increases of more than a few percentage points.

5. What it would take to improve Generating Efficiencies

The present cost of fuel in non-OECD countries is perceived to be a disincentive to achieving significant increases in generating efficiency. Only when fuel is expensive will competitive pressures by themselves lead to efficiency improvements. Stricter environmental requirements could play a role (especially constraints on carbon dioxide emissions). Governments can mandate efficiency standards, but this is not seen as likely unless there is a strong national or international reason for doing so.

There is a common perception of higher capital and operating cost, and risk of reduced plant operating reliability, associated with supercritical pulverised coal technologies, both among IPPs themselves and, perhaps more important, among their engineering and technology supply partners. The latter are normally expected to bear the technology risk in an IPP project, which tends to bias them towards conservatism. Some of the higher cost may also in fact be due to the higher perceived risk premia in project-financed IPP plants. There may be an information gap here that could be bridged by further dialogue.

The responses to the IPP Survey have highlighted a perception that supercritical pulverised coal technology is both costlier and riskier than conventional subcritical technology. How justified is that perception? The other part of this assessment, described in Section III. below, attempts to respond to this question.

III. Comparison of Supercritical Versus Subcritical Plant performance

In order to assess the cost-effectiveness and environmental performance of SC and USC coal-fired generating plants versus a "conventional" subcritical plant of the type used in most IPP projects today, an analysis of comparative performance and cost was carried out using the SOAPP data-base, for a 600 MW PC-fired plant in an Asian location. The plant capacity factor is 81%. The coal sulphur content is 0.9%.

For this case study, the following scenarios were evaluated:

(1) 2400 psig subcritical plant with an electrostatic precipitator for particulate control and low-NOx burners, but no post-combustion sulphur or nitrogen oxide controls (Conventional Plant).

(2) 3500 psig supercritical plant (SC).

(3) 4500 psig ultra supercritical plant (USC).

(4) 4500 psig ultra supercritical plant with spray dryer FGD, SCR, and baghouse for particulate control (USC w/FGD, SCR).

The analysis was carried out for two variants of capital cost and for two types of coal. The higher level of capital cost (~\$800/kW for a subcritical plant without FGD) corresponds to that for a plant built in an advanced OECD country, and the lower capital cost (~\$620/Kw) to that for a similar plant constructed in a developing country such as China. The lower priced coal (~\$15/short ton, heating value 7900 Btu/lb) might be that for a minemouth coal plant, and the higher coal price (~\$40/short ton, heating value 12000 Btu/lb) might be the landed price of internationally traded coal at a coastal power plant.

1. Plant Efficiency

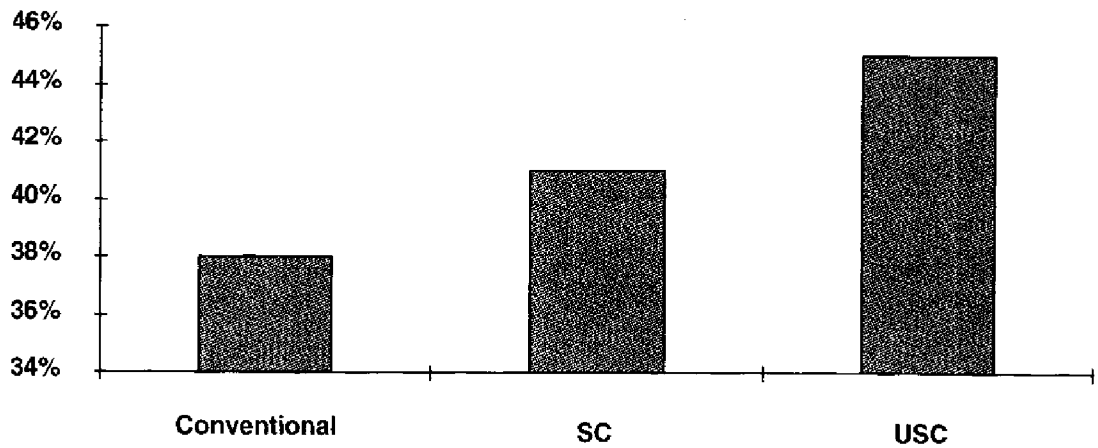
The plant efficiency comparison is shown in the Figure 4. Compared to the conventional subcritical plant's 38% efficiency, a supercritical plant can readily achieve 41% and an ultra-supercritical one 45% on an LHV basis. It would be possible for a subcritical plant to achieve greater efficiency via higher temperatures (up to about 40%). The "conventional" plant in this comparison, however, is intended to represent one typical of many IPP coal plants currently in operation, construction, or project development.

2. Fuel Consumption

The plant efficiency improvements result in significant reduction in fuel consumption. A 600 MW conventional plant has a primary fuel feed rate (100% load) of ~ 750,000 lb/hr. The more efficient USC plant has a primary fuel feed rate of 645,000 lb/hr. This translates to over ~375,000 short tons/year of coal not combusted, which results in a fuel cost savings of approximately \$6 million/year for a USC plant vs. a conventional plant based on a fuel cost of \$15 per ton delivered (calorific value 7900 Btu/lb), or approximately \$10 million/year if the fuel cost is \$40/ton (calorific value 12000 Btu/lb).

Figure 4

Plant Efficiencies (LHV)
Supercritical Versus Subcritical



3. CO_2 Emissions

With the recent attention focused on the international greenhouse issue, emissions of CO_2 from coal-fired power plants have received increasing attention. The annual mass CO_2 emissions for the conventional, SC and USC plants are ~5.2 million short tons, 4.8 million tons, 4.4 million tons, respectively (Figure 5). This represents 8% emission reduction for the SC and 15% for the USC plant relative to the conventional subcritical technology. Consequently, even the intermediate step of the supercritical plant reduces CO_2 emissions by almost a half million tons per annum for a 600 MW plant, or 0.7 million tons/GW. Over the 40 year lifetime of 1 GW of new coal generation, 28 million tons less CO_2 would be emitted. Asia alone may need to construct 15 GW per year of new coal generation over the next two decades, according to the IEA's World Energy Outlook (9). Thus one year's incremental generation would produce 420 million tons less CO_2 during its lifetime, and the savings from one decade of this growth would amount to almost 5 billion tons of CO_2. And going to ultra-supercritical plants would double this. The stakes are clearly rather high.

4. SO_2 and NOx Emissions

Emissions of gaseous pollutants are also reduced by building more efficient plants. The emission control equipment required for a plant depends on the coal selected and the applicable emission regulations. Currently, most plants in Asia are being installed without FGD Systems and with low NOx boiler burner equipment. This approach is based on the use of low sulphur coal, the cost, and current national air emission regulations or World Bank environmental guidelines. Emissions of both conventional pollutants (SO_2, NO_X, particulate, etc.) and carbon dioxide are lower for the more efficient supercritical plants than for the traditional subcritical plant. When comparing plants without post-combustion air pollution controls, mass emissions of SO_2 are reduced by 3300 tons/year, and emissions of NO_x by 1180 tons/year for a USC plant compared to a conventional plant (Figure 6).

With the use of state-of-the-art air pollution controls, emissions of conventional pollutants can be reduced to ultra-low levels. The USC plant equipped with a lime spray dryer, SCR, and baghouse can produce emissions of 0.11 lb/MBtu SO_2, 0.06 lb/MBtu NO_X, and 0.005 lb/MBtu particulate. The emissions could be reduced by up to ~90% with this percentage sulphur coal. This low emissions boiler would be able to satisfy the most stringent regulatory requirements. The additional capital cost for this system on a 600 MW unit with low sulphur coal fuel (0.9%) would be approximately $130/kW. This cost increment is relatively low because the spray-dryer/baghouse combination is substituted for the precipitator included in the other cases.

5. Plant Reliability

Though this was not a variant in this assessment, it is worth a brief mention of the issue of supercritical versus subcritical power plant reliability. Experience with the higher

Figure 5

Carbon Dioxide Emissions
(Million Tons/year, 600 MW Unit)

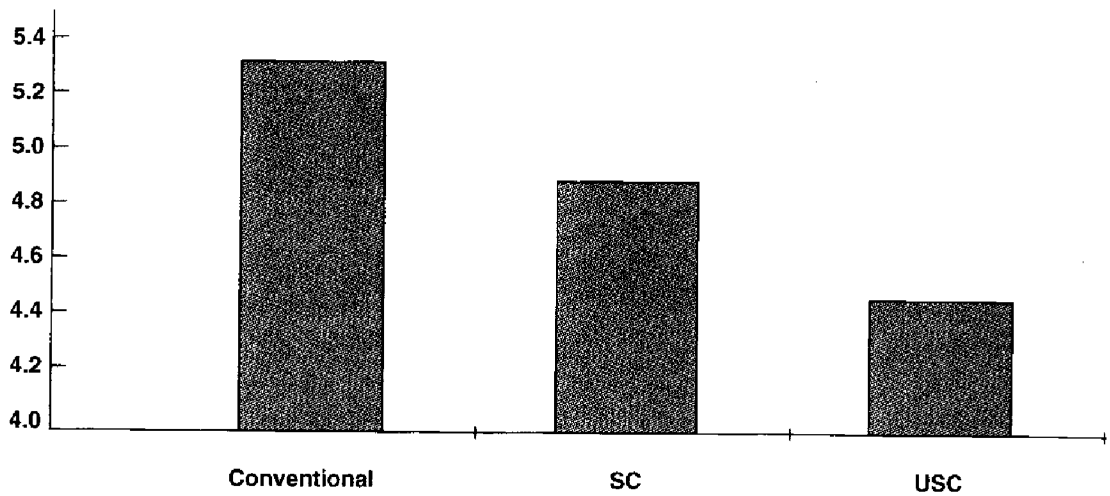
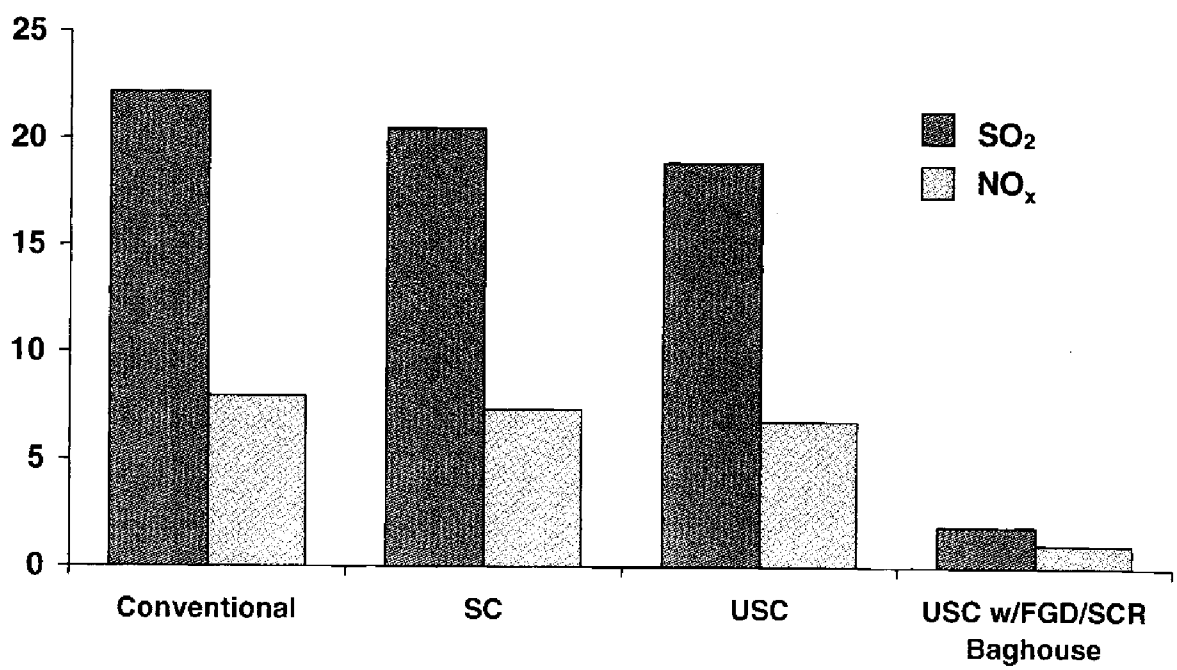


Figure 6

SO_2 & NO_X Emissions
(1000 tons/year, 600MW Unit)



temperatures and pressures involved in supercritical technology has grown substantially over the past two decades, and earlier technical problems have been to a large extent overcome by improvements in materials and design. There remain some corrosion problems stemming from the higher temperatures, which makes supercritical less suitable for high slagging or corrosion coals. Coal with greater than about 2% sulphur has caused some superheater and reheater difficulties. However, these difficulties are not necessarily specifically related to the sulphur content - coal chlorine and other constituents can have a major impact on the corrosion rates.

There are options which boiler manufacturers can employ with more corrosive coals to mitigate these problems. Boiler design optimisation options include a larger furnace for lower gas temperatures entering the reheater and superheater, use of higher alloy materials which have recently become available, tube shields, a tube cooling screen before the superheater and reheater, boiler water and steam circuitry to reduce high gas temperatures because of uneven gas and steam/water exchange in the combustion and other heat transfer zones, and other means.

Boiler tube leaks are a major issue for plant operation, often being the cause of loss of reliability. There is occasionally a tendency to generalise the difficulties caused by tube leakage problems, e.g. water wall leaks are not differentiated from superheater and reheater problems. However, tube leaks are often caused by water chemistry problems and not directly related to the coal quality. Many units have switched to "oxygenated" cycle chemistry, which has proven to reduce tube leaks very substantially.

It is possible that commercial risks for a supercritical plant burning greater than 2% sulphur coal might be subject to greater premiums owing to less historical experience. However, many of the plants to be built in Asia over the coming decades will use relatively low sulphur coal, so this issue may be only be encountered for plants attached to some specifically higher sulphur reserves.

IV. COST COMPARISON OF SUPERCRITICAL VERSUS SUBCRITICAL PLANTS

The capital costs differences (higher capital cost case) are shown in Table 2, which also separates out the main items for which the cost increases in the supercritical and ultra-supercritical plants relative to the conventional plant.

Table 2. Capital Costs of Supercritical versus Subcritical Generating Plants

$/kW		Subcritical	Supercritical	Ultra-Supercritical	Ultra-Supercritical with FGD System & SCR
Boiler (incl.steel;, air heater, etc.)		$142.94	$153.09	$163.52	$163.52
% compared to base		Base	107.1%	114.4%	114.4%
Boiler plant piping		$27.81	$31.03	$31.81	$31.81
% compared to base		Base	111.6%	114.4%	114.4%
Feedwater systems		28.06	$28.62	$29.18	$29.18`
% compared to base		Base	102.0%	104.0%	104.0%
Turbine-Generator		$79.20	$82.37	$83.95	$83.95
% compared to base		Base	104.0%	106.0%	106.0%
Turbine plant piping		$16.25	$15.44	$15.43	$15.43
% compared to base		Base	95.0%	95.0%	95.0%
Subtotal for boiler, turbine, high pressure piping, feedwater systems		$294.26	$310.38	$323.91	$323.91
% compared to base		Base	105.5%	110.1%	110.1%
Remainder of Plant		$509.17	$500.69	$487.17	$604.76
% compared to base		Base	98.3%	95.7%	118.8%
Total Plant Cost		$803.43	$811.07	$811.08	$928.67
% compared to base		Base	101.0%	101.0%	115.6%

The plant would have two units with low NOx burners, high efficiency particulate collection equipment, once through sea water cooling, including the switch yard and all the facilities for a new site location, and a 60 month construction schedule. The capital costs in Table 2 include the plant equipment, structures, switchyard, and coal unloading facilities.

The increases in cost for the higher pressure cycles plants are not as high as was evident in previous evaluations performed several years ago, because of better materials, equipment designs and other technological knowledge, and growing experience with the higher pressure and temperature cycles. Another factor is the beneficial impact of the higher efficiency cycle on the overall plant costs, in the form of reduced costs for smaller coal handling systems, precipitators, and cooling systems, etc. These cost reductions offset the increased costs for the higher pressure and temperature cycle boiler, turbine, piping, pump, feedwater heater, etc. equipment. This is shown graphically in Figure 7.

It is of course a valid question as to whether the substantial cost savings realised during recent years in subcritical plant design and construction may not be easily translated to supercritical and ultrasupercritical designs. While it is unlikely that plant designs for supercritical have reached the same "off-the-shelf" sophistication which the construction engineering firms now offer for subcritical plants, there is no a priori reason why the same competitive forces which led to these offerings should not come into play as soon as there is a demand for cost-effective supercritical plants.

Table 3 summarises the economic parameters used to calculate the cost of electricity generated from the different types of plant.

Table 3. Economic Parameters uses in the Comparison

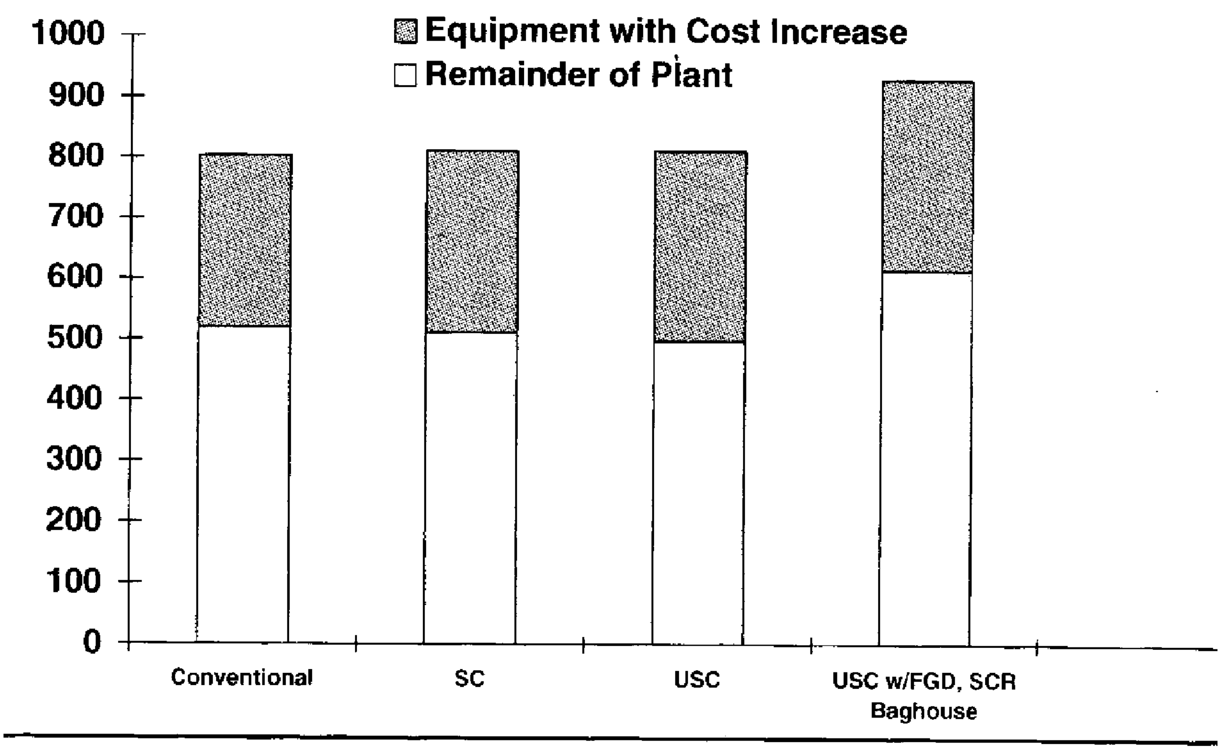
Plant Operating Period = 30 Years	Fuel Cost A = \$15.20/ton, B = \$40/ton
Plant Operating Hours = ~ 85% availability	Interest during construction = 9.8%
Capacity Factor = ~80%	O&M Escalation 2%
Fixed Charge Rate = 13%	\$5/ton Waste Disposal Costs
O&M (fixed) = ~ \$13/kW-year	

Capital charges and fixed O&M are higher for the SC and USC cycles, while total fuel costs are lower for the SC and USC because of the higher efficiencies. The O&M cost estimate was developed using the methods and data typically used for economic comparisons for new projects. The average availability for all three pulverised coal generating cycles included in this study is 85% and the capacity factor for all the units is 80%. This target is based on data from existing plants.

Figure 7

Capital Cost Comparison for 2x600 MW Coal Fired Powerplant

Higher Capital Cost Case



The results are shown in Figure 8(a) and (b) for the lower coal price and Figure 9(a) and (b) for the higher coal price. In each of these Figures, (a) is the higher capital cost case and (b) the lower capital cost case. As expected, the effect of fuel price is very significant. When the higher level of capital cost is used in the analysis, going from conventional to supercritical in the lower coal price case reduces the electricity cost by 0.08 cents/kWh, and in the higher coal price case by 0.23 cents/kWh - almost a factor of three. The corresponding reductions in going from conventional to ultrasupercritical are 0.14 cents/kWh in the lower coal price case and 0.48 cents/kWh in the higher coal price case. Figure 9 shows that the ultrasupercritical plant with state-of-the-art sulphur and nitrogen oxide controls and a high efficiency baghouse for particulate control can produce cheaper electricity than a conventional plant with only a precipitator for particulate control!

When the lower capital cost is used in the analysis, the corresponding reductions in going from conventional to ultrasupercritical are 0.15 cents/kWh in the lower coal price case and 0.46 cents/kWh in the higher coal price case, implying that the choice of whether to use subcritical or supercritical technologies is not very sensitive to general capital cost levels.

V. CONCLUSIONS

The independent power sector has been and remains reluctant to employ advanced clean coal technologies for power generation projects. The current standard appears to be a subcritical pulverised coal plant with flue gas clean-up adequate to meet World Bank Environmental Guidelines. Only minor improvements in generating efficiency are expected by the IPP sector over the next five years.

Advanced clean coal technologies like PFBC and IGCC are expected by independent power producers to be selected only in special cases where their risks are fully covered and incremental costs recovered in the price of electricity produced. Their market penetration on a wider scale without special treatment is seen by the IPPs as being in the 2005-2010 timeframe or beyond. It appears that the only way to accelerate this is to complete a number of successful demonstrations which, in particular, show that advanced clean coal plants can be operated reliably and with superior performance, and specifically that their present estimated capital costs can be reduced substantially to a point where they are competitive with state-of-the-art pulverised coal technologies.

Supercritical pulverised coal technology is perceived as available but more costly and containing added risk in terms of reliability. Also, there are few incentives to employ it in non-OECD countries, especially where coal is inexpensive. There appears to be a perception problem, possibly due to lack of information, which may need to be addressed by the IEA and others, if the advantages of supercritical generating efficiency improvements, both environmental and economic, are to be realised in the near future.

Figure 8 (a)

Cost of Electricity (cents/kWh)

Lower Fuel Cost ($15/ton)
Higher Capital Cost Case

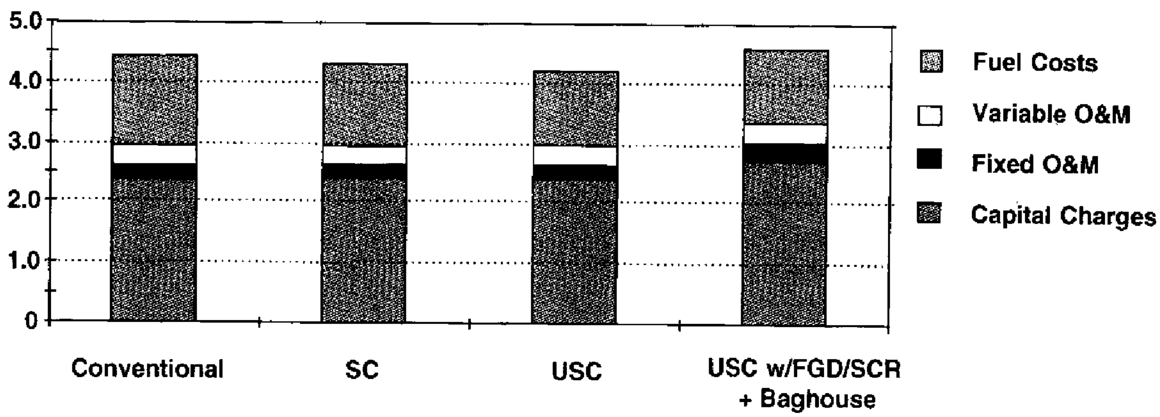


Figure 8 (b)

Cost of Electricity (cents/kWh)

Lower Fuel Cost ($15/ton)
Lower Capital Cost Case

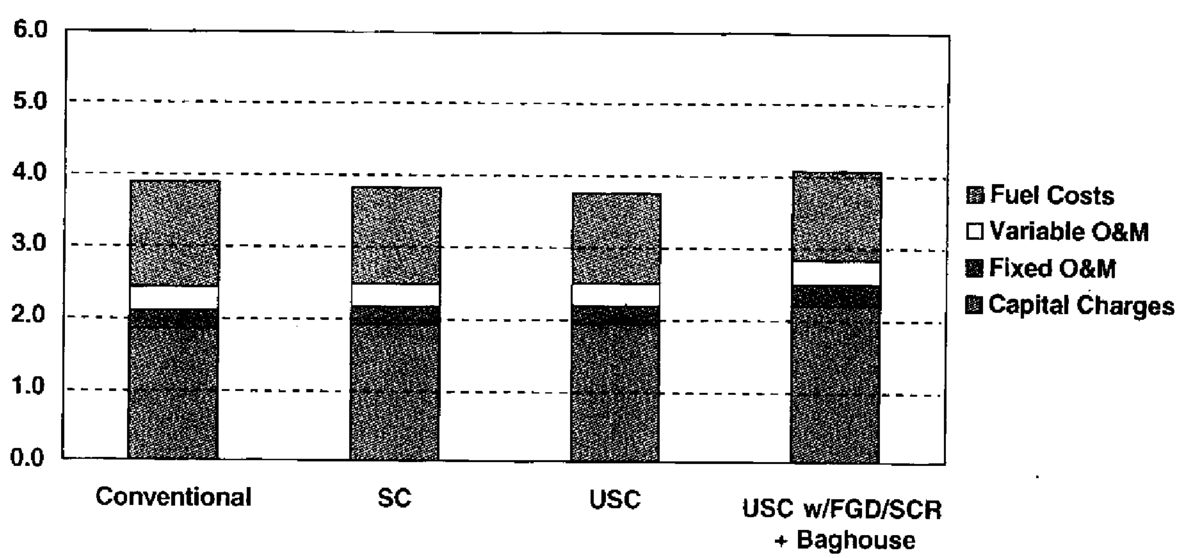


Figure 9 (a)

Cost of Electricity (cents/kWh)

Higher Fuel Cost ($40/ton)
Higher Capital Cost Case

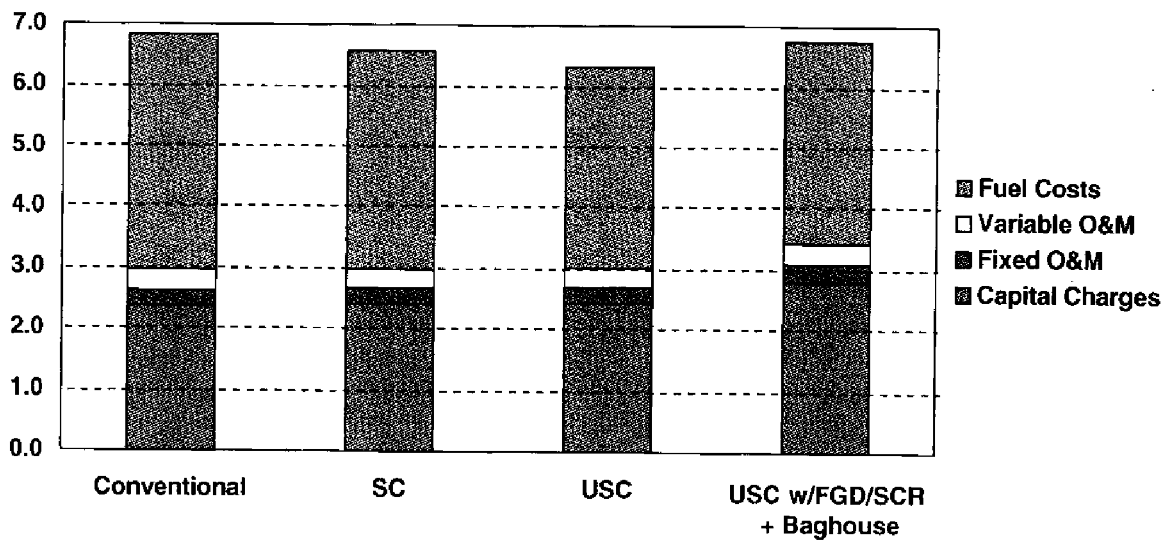
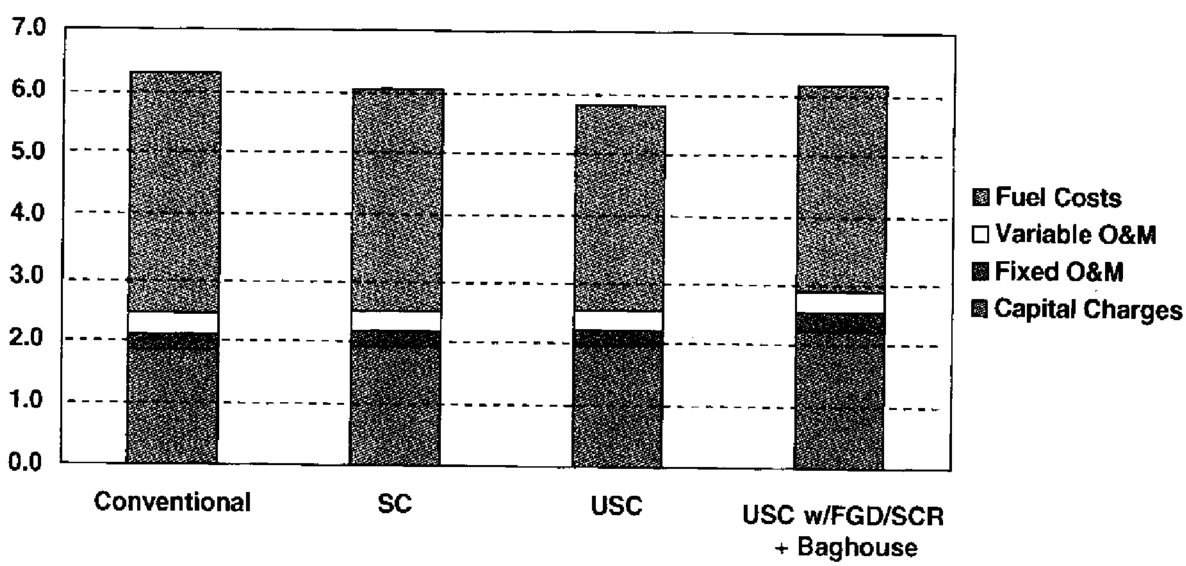


Figure 9 (b)

Cost of Electricity (cents/kWh)

Higher Fuel Cost ($40/ton)
Lower Capital Cost Case



An economic analysis of subcritical versus supercritical state-of-the-art pulverised coal power plants, carried out for the CIAB by SEPRIL, has suggested that supercritical generation is less costly in terms of cost per kilowatt hour of electricity generated. This is especially marked for higher fuel cost but still significant for lower cost fuel.

Two types of action are being undertaken to overcome the perception barrier with regard to supercritical generating technology:

(1) Development of communication among the stakeholders - governments, IPPs, major international construction engineering companies and technology suppliers - to confirm the cost and reliability figures for supercritical versus conventional subcritical technology;

(2) Discussion with financing entities - private banks, multilateral funding organisations, and government export credit agencies - to identify the risk issues and possible creative financing incentives which would encourage the use of more efficient generating technologies.

REFERENCES

1. *Development Plan for Advanced Fossil Fuel Power Plants*, EPRI Report CS-4029, Bilber Associates, 1985.
2. Turbine Designs for Improved Coal-Fired Power Plants, EPRI Research Project 1403-15, TR-100460, General Electric Company and Toshiba Corporation, edited by Encotech Inc., 1991.
3. *The Advanced Pulverised Coal-Fired Power Plant: Status and Future,* S. Kjaer, Elsamprojekt, 1994 ASME, International Power Generation Conference (PWR-40).
4. Keynote lecture of the VGB Conference, Kolding June 93, S. Kjaer - Elsamprojekt, H. Koetzier and J. van Liere - KEMA and I Rasmussen - Midkraft Power Company, Aarhus DK.
5. *Newly Developed High Temperature Ferritic-Martensitic Steels from USA, Japan and Europe,* R. Blum, Faelleskemiderne, Fynsvaerket, Odense, Denmark, et al., 1993 International VGB Conference Fossil-Fired Power Plants with Advanced Design Parameters.
6. *Development of Improved Boiler Startup Valves*, EPRI Report GS-6280, April 1989.
7. *Particle Erosion Technology Assessment*, EPRI Report TR-103552, December 1993.
8. *Circumferential Cracking of the Waterwalls of Supercritical Boilers*, EPRI Report TR-104442, September 1995.
9. *World Energy Outlook*, International Energy Agency, OECD, Paris 1996

CCT'S IN A DEREGULATED ENVIRONMENT:

A PRODUCER'S PERSPECTIVE

Robert F. Edmonds, Jr
Director, Business Development
Associated Enterprises Group
Duke Power Company

John O. Fayssoux
Project Director & Team Leader
Energy Services
Duke Power Company

ABSTRACT

The U.S. electric industry will be deregulated (or substantially re-regulated) within 5 years. Several states, including California, Rhode Island, and New Hampshire, already have passed legislation to introduce competition into the electric markets before the year 2000. As this trend sweeps across the country, the resulting competitive market for generation will reward the lowest cost producers and force high cost producers out of the market. As a result, at least in the short run, it may be very difficult for new power plants employing Clean Coal Technologies (CCTs) to compete. This paper discusses a producer's perspective of the new competitive market, and suggests several short and long term strategies and niches for CCTs.

I. INTRODUCTION

For more than 60 years, the electric utility industry has been highly regulated, as were industries like banking, trucking, telecommunications, and natural gas. But starting in the early 1970s, the United States began witnessing a transition from an environment of regulation to one in which market forces held greater sway. One by one over the next 20 years, these industries saw the regulatory veil lifted, exposing them and their customers to the benefits and uncertainties of market competition.

Throughout this period, many continued to believe that utilities were different and that deregulation was impractical and unnecessary. In the 1990s, however, the same forces that nurtured change in other industries — customer expectations of lower cost, more choice, greater innovation and better service — began to affect the electric utility industry. Today, the transition to a more competitive environment is well under way.

Global competition, coupled with rate disparities that can exist between assigned service territories, is the primary force behind the push for a market-driven electricity utility industry. As U.S. industries find themselves competing toe-to-toe with not only domestic but foreign enterprise, the pressure to keep production costs down is intensifying. As a result, industries are leading the call for a competitive electric market in the U.S. Many views exist of how a competitive market might function. Duke Power believes**(1)** a national market will evolve and that it will look much like the one now being developed in California.

Regardless of the form, there are a number of significant issues that can affect customers and the shareholders of publicly held utilities like Duke Power Company. These issues include:

- Maintaining fairness and equity between customer classes (e.g. residential, commercial, and industrial)
- Ensuring the world’s most reliable electric system remains so
- Maintaining parity among competing suppliers (e.g. subsidized generators are not allowed to compete with unsubsidized generators)
- Redefining the monopoly-based obligation to build generation to serve all assigned customers
- Recovering stranded investment
- Allocating equitable sharing of societal costs

These are difficult, critical issues, but if they can be fairly and appropriately resolved Duke Power supports the concept of electric utility deregulation. Duke advocates federal legislation to provide guidance to the states for implementing deregulation, including a time frame under which it would be instituted. Following federal action, each state should then be allowed to design its own specific solutions. Duke PowerÕs position on restructuring the industry is based upon the simple premise that deregulation should offer equal treatment of all customers, provide a level playing field for all competitors, and maintain the current high reliability of the electric system.

II. ONE VIEW OF A DEREGULATED INDUSTRY

While there are three primary functions of the electricity utility business (generation, transmission, and distribution), most proposals for deregulation are limited to the generation business because of its present level of competitiveness. Even in a competitive environment, the transmission and distribution businesses would most likely be separate entities under the regulation of the Federal Energy Regulatory Commission (FERC) and state regulatory commissions.

A number of proposals have been made concerning deregulation. Among the many competitive market proposals considered, one promising idea for restructuring calls for creating a new structure built on two fundamental concepts:

- The primary source of electricity for all customers could be through a regional power pool. Participants in the power pool would primarily be generators, customer representatives referred to as ÒaggregatorsÓ or Òretail companiesÓ, and end-use customers.

- A secondary source of electricity could be through bilateral contracts between willing generators and end-use customers or aggregators.

A power pool could be comprised of two new regulated organizations: the Power Exchange (PX) and the Independent System Operator (ISO). Both would be independent businesses that would be governed and managed separately from the financial interests of market participants. Whether management of the PX and ISO would be separate entities is still an open question, but the roles and responsibilities of each are best described separately.

The Power Exchange

The role of the PX could be to facilitate trading in a visible spot market in which generating resources compete by:

- Taking supply bids from generators and demand bids from utilities, retail companies, power marketers and others;
- Allowing power producers to compete using non-discriminatory and transparent rules for bidding into the exchange;
- Ranking bids and submitting to the ISO a preferred least-cost dispatch schedule for delivering power; and
- Providing a visible market clearing price to permit customers to make efficient purchasing decisions and to adjust consumption.

Independent System Operator

The ISO would provide daily transmission system information to all market participants and collect bids by market participants to provide ancillary services for the next day. The ISO would control the transmission system and coordinate the hourly dispatch of the generation system in a reliable manner. The ISO could:

- Provide non-discriminatory open access to the transmission network;

- Coordinate day-ahead scheduling for all transmission network users;

- Control operation of the combined transmission facilities of the participating transmission owners;

- Obtain ancillary services, (reserves, for example) for all transmission network users on a competitive basis;

- Perform a settlement function to account for actual operating conditions ;

- Provide transparent information flow to all transmission network users;

- Facilitate bilateral contracts between generators and customers;

- Comply with all operating and reliability standards; and

- Manage transmission congestion and constraints on a network basis with all users subject to the same terms of access, protocols and prices.

Transmission congestion charges could be administered by the ISO (in accordance with FERC approved tariff provisions) to provide pricing signals as inducements to market participants to build congestion-relieving transmission upgrades in needed areas. A separate mechanism or regulatory "backstop" may be put in place if generation or transmission is needed for the sake of reliability and the market fails to react appropriately. The ISO will not own any transmission or generation resources, but could have compelling incentives to help ensure system reliability.

Figure 1 illustrates the basic concept of a power pool.

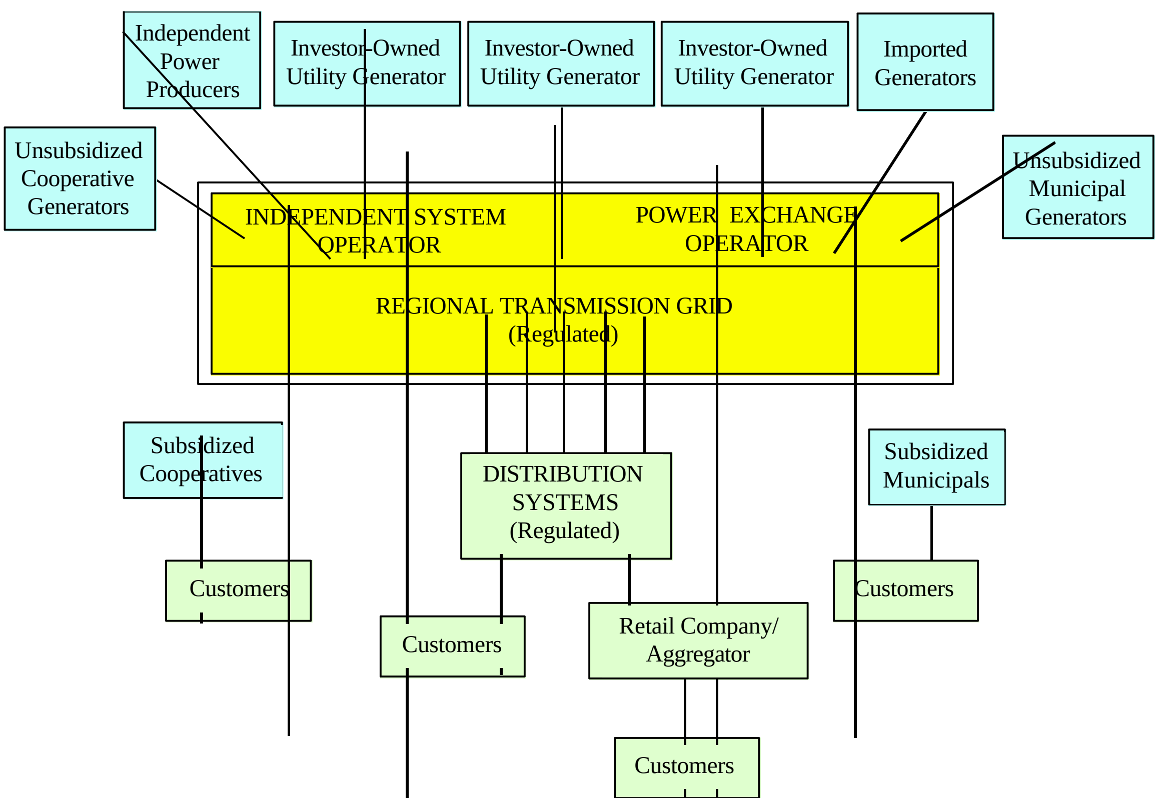


Figure 1. Basic Power Pool Operation

This combination of a PX, an ISO, and bilateral contracts is sometimes referred to as a "flexible pool" because it is designed to provide flexibility in contracting and trading arrangements. The flexible pool could offer all consumers electricity at competitive prices and also give all generators an equal chance to serve the available customer base. In some cases, an aggregator or a retail company could procure and provide these competitively bid generation services to customers.

While many details must still be resolved, the basic concept for the flexible pool could provide the foundation for advancing competition without compromising reliability or giving any competitor an unfair advantage.

III. CCTs IN THE DEREGULATED MARKETPLACE

If the marketplace described above comes to pass, it will have a number of impacts on the use of CCTs, some positive, but most negative--at least in the short run.

Lowest Operating Cost Wins

First, the competitive generation market will be more difficult for <u>any</u> new entrant, but especially so for plants with higher capital and operating cost. If existing plants are allowed to recover their *stranded costs*--i.e. that portion of their fixed costs not otherwise recovered by the competitive price of power--then any <u>new</u> plant will have difficulty competing with <u>existing</u> generators. This will hold true until the existing excess generating capacity is depleted. (Note: Depletion could be the result of demand growth, obsolescence of older plants, environmental/regulatory action against an existing technology, etc.) Then, when new generation is needed anyone considering entering the market will ask themselves these questions:

Which technology will produce power for the least overall cost?
- High cost = non-competitive
- No more automatic cost recovery in utility rates

Which technology has the least risk--technical and financial?
- Risk translates into higher cost

Which technology can be brought on line quickest?
- Time is money
- Competitive markets can be fickle, change rapidly

Currently the answer to all these questions would be combined cycle gas turbines in either a stand-alone power plant or in a cogeneration mode. As long as gas prices remain reasonably low, gas turbines will continue to be the technology of choice.

Technology Risk is a Killer

Technology risk associated with new CCT-based generators will cause these plants to suffer in the competitive market for two reasons. First, the equipment cost will have a "technology premium" to cover development costs and performance risk. Second, and probably more critical, the project owners will pay a risk premium on any borrowed funds. Lenders have shown little appetite for risk in the independent power market that has dominated the placement of new capacity for the last decade. There will be even less appetite for risk where the payment stream used for debt coverage comes from the competitive marketplace and not a "secure" long term contract with a utility, as existed in the recent past.

The "Level Playing Field" Issue

A potential obstacle to new CCT-based generation is the notion that in a competitive generation market, no generator should be allowed to compete if it receives a subsidy--such as tax-exempt bonds or government loans--that is not available to all generators. This position is held by most investor-owned utilities, including Duke Power. And, since approximately 80% of all generation in the US is owned by investor-owned utilities, this position is likely to prevail. If it does, it would mean that CCT projects which received DOE grants or loans would either have to seek special status or find ways to mitigate their competitive advantage.

Fuel Diversity is a Wild Card

Potentially the greatest advantage CCTs have in the deregulated marketplace is that they provide fuel diversity. But it is unlikely that producers, left to their own devices, will place much emphasis on fuel diversity, especially in the near term. However, two things could change that likelihood. First would be a near-term spike in gas prices. The US has seen a decade of stable, even falling, gas prices. This has caused a widespread shift away from coal and toward gas-fired technologies. Another oil embargo, a Gulf crisis, or a natural disaster in a major gas-producing region could push gas prices up to the point where generators will choose an alternative fuel.

Alternatively, the federal or state governments could weigh into the utility deregulation debate with their concerns about fuel diversity. It will likely take government intervention to force fuel diversity arguments to be heard. It appears, based on positions published before the recent election, that while the Clinton Administration is lukewarm toward electric deregulation, it will insist that fuel diversity be considered in future rules. States also, to the extent they are involved in setting the deregulation rules, may insist on fuel diversity and, possibly, use of indigenous fuels like coal.

Environmental Issues--Mixed Bag

Environmental issues are a mixed bag in terms of their impact on deployment of CCTs. Emissions limitations could force owners of older coal-fired plants to retrofit CCTs to comply with more stringent limits. This could be particularly true where older plants, many with minimal emissions controls, are pressed into service in the competitive marketplace. Capacity factors could increase dramatically on these plants as the competitive price of energy increases due to increased demand. Indeed, there is a fear among many environmentalists that this is precisely what will happen. CCTs could mitigate that fear.

But while environmental issues could increase the use of CCTs retrofitted to older plants, there does not appear to be a similar beneficial impact on new CCT-based plants. This is true because currently even the best CCT environmental emissions are no better than those from similar-sized gas turbine plants. The impressive environmental records of many of the new CCTs can certainly be used to *support* their use (for example to mitigate fuel diversity concerns) but environmental records alone will not endow a marketplace advantage on CCTs vis-à-vis gas plants.

IV. CCT OPPORTUNITIES

The major cost drivers for a new power plant are capital cost and fuel (including transportation) cost. It is currently a universally recognized fact that there are few, if any, places in the US where a coal plant can produce power cheaper than a gas-combined cycle plant, provided gas is available. And there are only two states, Hawaii and Maine, where natural gas is not available. Therefore, unless promoted for fuel diversity reasons, coal must either find ways to reduce the all-in cost of power or find niche opportunities.

Reducing Conventional Coal Plant Costs

Although the focus of this paper is on the future of CCTs, it is instructive to look at the competitiveness of a conventional coal plant in today's environment. One of the most recent conventional coal-fired plants to be brought into service in the US was Cope Generating Station, completed in late 1995 by Duke/Fluor Daniel, a Duke Power affiliate.(2) This plant, built for South Carolina Electric and Gas, is the least cost coal plant built in recent years. The $411 million plant generates 385mw at 95% valves open. At full valves open, this equates to a little over $1000/kw of capacity.

In building the Cope plant, Duke/Fluor Daniel utilized a number of cost cutting measures which had been developed in several recent international plants. Most effective were (1) world-wide sourcing of equipment, and (2) a sophisticated Computer Aided Design package developed by Duke/Fluor Daniel called PowerSuite. These and other cost saving techniques can keep the cost of coal plants down, but, as illustrated below, more is needed if coal is to compete with gas.

In contrast to the $1000/kw price for coal plants, similar sized gas combined cycle capital costs are approximately $500/kw. Assuming roughly equal O&M costs (a generous assumption for coal), approximately a 50% to 35% efficiency advantage for gas, and gas at $3.00/mmBTU, then coal prices per million BTU must be around $1.00 to be competitive. See Table 1 below.

	Coal Plant	**Gas Combined Cycle Plant**
Capital Cost	$1000/kw	$500/kw
Efficiency	35%	50%
Fuel Cost*	$1.05/mmBTU	$3.00/mmBTU

*For power cost from coal to equal gas at $3.00, coal must be this

Table 1. Comparison of Coal And Gas Plants

Therefore, with existing capital cost and efficiencies for coal and gas plants, coal prices must be less than gas by a 3:1 margin to make the generation owner indifferent to technology. Put another way, gas prices would have to suffer a 50% increase before coal at $1.50/mmBTU would become cost competitive.

The only place in the US where coal can currently be obtained for $1.00/mmBTU is at the mine. Consequently, mine-mouth coal plants can be competitive. In the fully competitive marketplace described above, i.e. open, boundary-less transmission access, mine-mouth power plants may be an attractive option.

CCTs as Backup to Gas

As noted above, gas combined cycle plants have a significant advantage over conventional coal today. Gas can also beat any known CCT including coal gasification and PFBC. But that doesn’t mean there is no place for CCTs. In fact some gas combined cycle plants being built today have included space to convert to coal gasification-combined cycle later. But one shouldn’t look for CCT hardware orders soon, because no generation owner can afford to invest capital in a backup technology until there is a clear pricing signal that the fuel price advantage of gas is on the verge of changing.

Co-Production

Among the CCT's that are demonstrated and nearing commercial availability, coal gasification-combined cycle (CGCC) technologies may have a slight market edge over others since they are capable of co-production. CGCC plants are, in the simplest terms, a chemical plant that produces synthetic natural gas along with other useful byproducts such as steam, hydrogen, ammonia, sulfur and re-useable ash products. Therefore, in addition to producing useful steam and electricity in a classical cogeneration configuration, CGCC plants are capable, with additional capital investment in the gas production portion of the plant, of producing revenue-producing byproducts. Revenues from the co-production of useful chemicals and solid byproducts, to the extent they are greater than the carrying cost of the extra capital employed to produce them, can be used to reduce electricity costs. This scheme may be particularly effective if co-located with a major petrochemical plant or other chemical-based manufacturing facility.

Alternative Fuels

Although not a new idea, the concept of using alternative fuels as a substitute or supplement to coal in a CCT may allow the CCT to penetrate the market earlier than a plant fueled by coal only. Fuels like petroleum coke, sewage sludge or waste coal have been proposed by others.

V. CONCLUSIONS

The coming deregulated electric market will reward the lowest cost producers of power and punish all others. CCTs that allow older, lower cost coal plants to continue operating without pushing their production costs above the competitive price of electricity will have a bright future. New coal plants that employ CCTs must be able to generate at lower production costs than gas in order to be considered by any producer wishing to stay in business. It is not a question of "<u>Will</u> CCTs be a player in the deregulated marketplace?", but rather a question of "<u>when</u>". Or more precisely, "When will electricity prices, gas prices, and capital cost of CCTs converge favorably to the point where a generation owner will invest in the CCT?" But, in the meantime, there are some strategic reasons and some niche opportunities that may work to allow CCT-based capacity to penetrate the market earlier.

VI. REFERENCES

(1) "Restructuring the Electric Utility Industry: A Position Paper", Duke Power Company, November 1996.

(2) "Electricity Flows from New SCE&G Generating Plant", News Release, South Carolina Electric and Gas Company, January 15, 1996.

Market for New Coal Powerplant Technologies in the U.S.
1997 Annual Energy Outlook Results

Mary J. Hutzler
Director
Office of Integrated Analysis and Forecasting
Energy Information Administration

Abstract: Over the next 20 years, the combination of slow growth in the demand for electricity, even slower growth in the need for new capacity, especially baseload capacity, and the competitiveness of new gas-fired technologies limits the market for new coal technologies in the U.S. In the later years of the 1997 Annual Energy Outlook projections, post-2005, when a significant amount of new capacity is needed to replace retiring plants and meet growing demand, some new coal-fired plants are expected to be built, but new gas-fired plants are expected to remain the most economical choice for most needs. The largest market for clean coal technologies in the United States maybe in retrofitting or repowering existing plants to meet stricter environmental standards, especially over the next 10 years. Key uncertainties include the rate of growth in the demand for electricity and the level of competing fuel prices, particularly natural gas. Higher then expected growth in the demand for electricity and/or relatively higher natural gas prices would increase the market for new coal technologies.

I. Key 1997 Annual Energy Outlook Results

Over the next 20 years the demand for electricity is expected to continue to increase with economic growth (Figure 1). However, the combination of increased market saturation of electric appliances, improvements in equipment efficiency, utility investments in demand-side management programs and legislation establishing more stringent equipment efficiency standards has slowed the rate of growth from the level seen in the 1960s and 1970s. Overall the demand for electricity is projected to grow 1.5 percent annually, with the residential and industrial sales growing faster than commercial sales (Figure 2).

The need for new capacity, especially baseload capacity, is expected to grow slower than total demand. Between 1995 and 2015 total U.S. generating capacity increases from 767 to 970 gigawatts, an annual rate of increase of 1.2 percent. However, due to the expected retirements of 38 gigawatts of existing nuclear capacity and 71 gigawatts of existing fossil-steam capacity, total capacity additions amount to 310 gigawatts over the next 20 years (Figure 3). Nuclear plants are assumed to retire at the end of their 40-year license period or before if their operating and maintenance costs exceed 4.0 cents per kilowatt hour. Fossil-steam plant retirements include reported retirement plans from utilities and the retirement of high operating cost units that would not be competitive in a deregulated environment.

Figure 1. Population, Gross Domestic Product, and Electricity Sales Growth, 1960-2015 (Index, 1960 = 100)

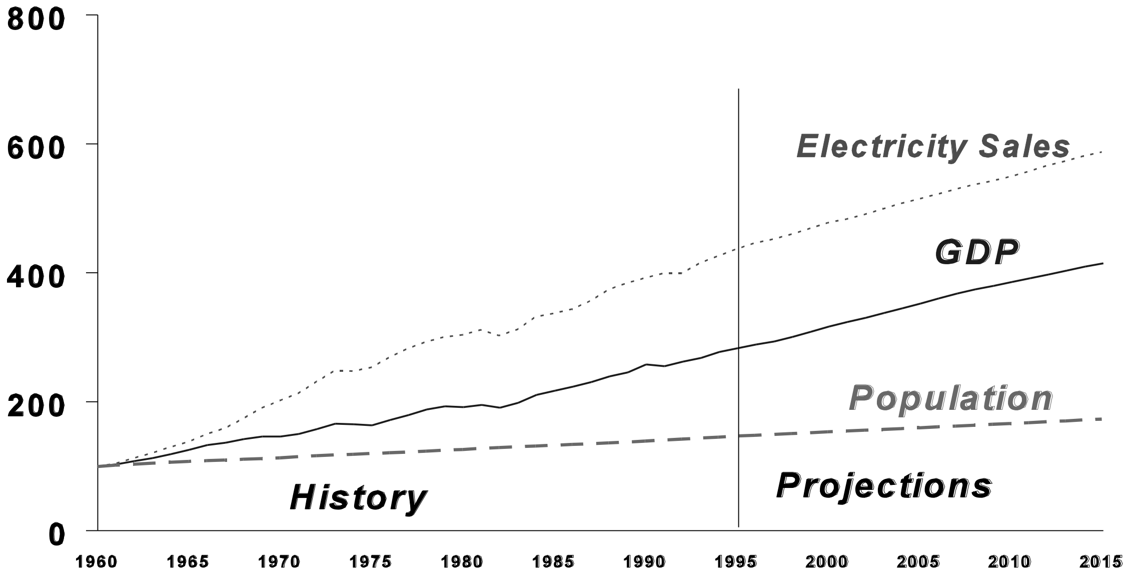


Figure 2. Electricity Sales by Sector, 1970 - 2015 (Billion kilowatthours)

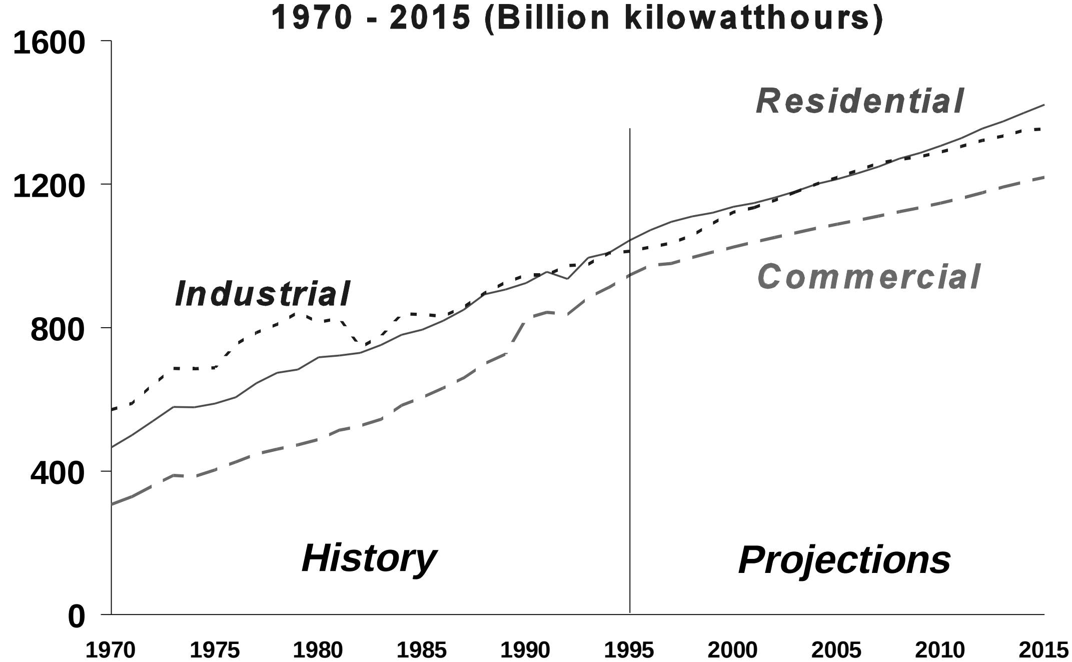
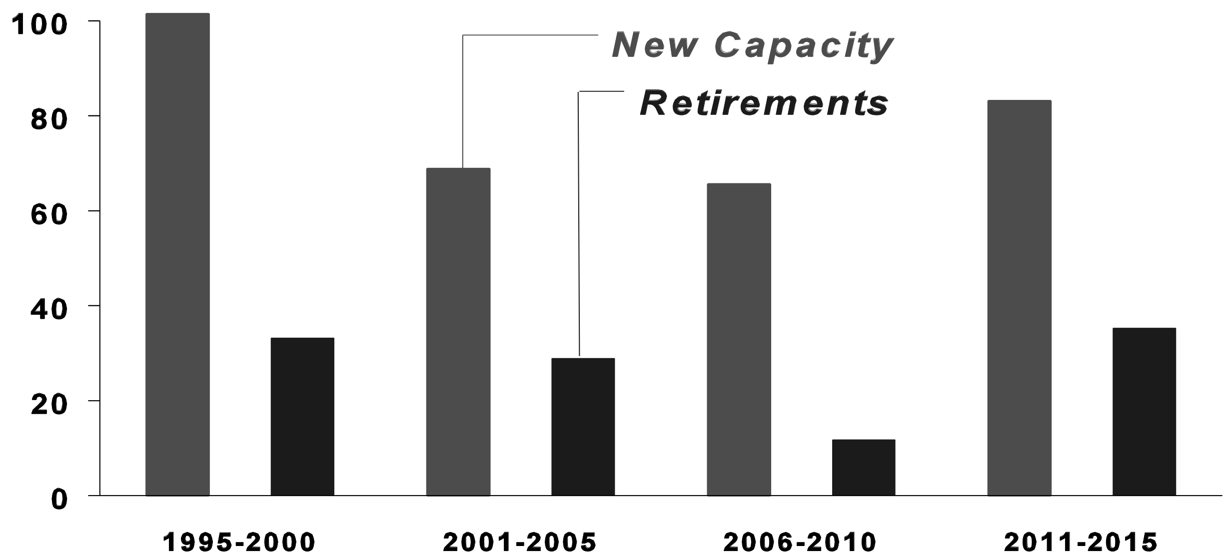


Figure 3. New Generating Capacity and Retirements, 1990 - 2015 (Gigawatts)



Natural gas-fired combustion turbines and combined-cycle units are expected to dominate new plant additions, especially in the near-term (Figure 4). About 80 percent of the capacity additions over the 1995 through 2015 period are projected to be gas-fired. Coal-fired and renewable (and other) plants account for the remaining capacity (11 and 8 percent, respectively). In the near term, between 1995 and 2000, new capacity is expected to be built to meet peaking needs. As a result, 65 percent of the gas-fired capacity built in that period are simple combustion turbines while the rest are combined-cycle plants. This pattern reverses itself in the last five years of the forecast when new plants are needed to serve growing baseload and intermediate demands. Over this 5 year period combined-cycle plants account for about 75 percent of the gas-fired plants added.

It is also during the later years of the forecast, 2005 to 2015, when most of the new coal plants projected to be added are brought on line. About 70 percent of the 37 gigawatts of coal plants projected to be built between 1995 and 2015 are brought on-line in 2005 and later. Over the 20 years of the projections, gas and coal prices to powerplants slowly diverge, with gas prices rising at approximately 1 percent per year (most of this increase occurs after 2005) while coal prices decline at a rate of 0.9 percent annually (Figure 5). In some regions of the country this widening fuel cost differential is large enough to allow new coal plants to be competitive with gas plants even though they cost much more to build. The vast majority, approximately 75 percent, of the

Figure 4. Electricity Generation and Cogeneration Capacity Additions by Fuel Type, 1995 - 2015 (Gigawatts)

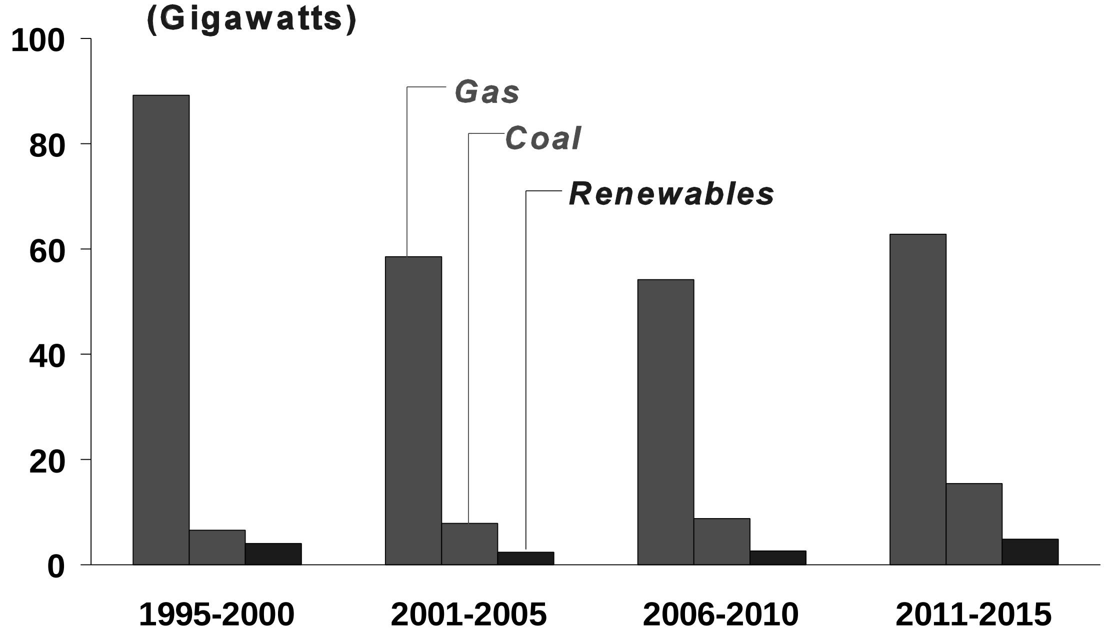
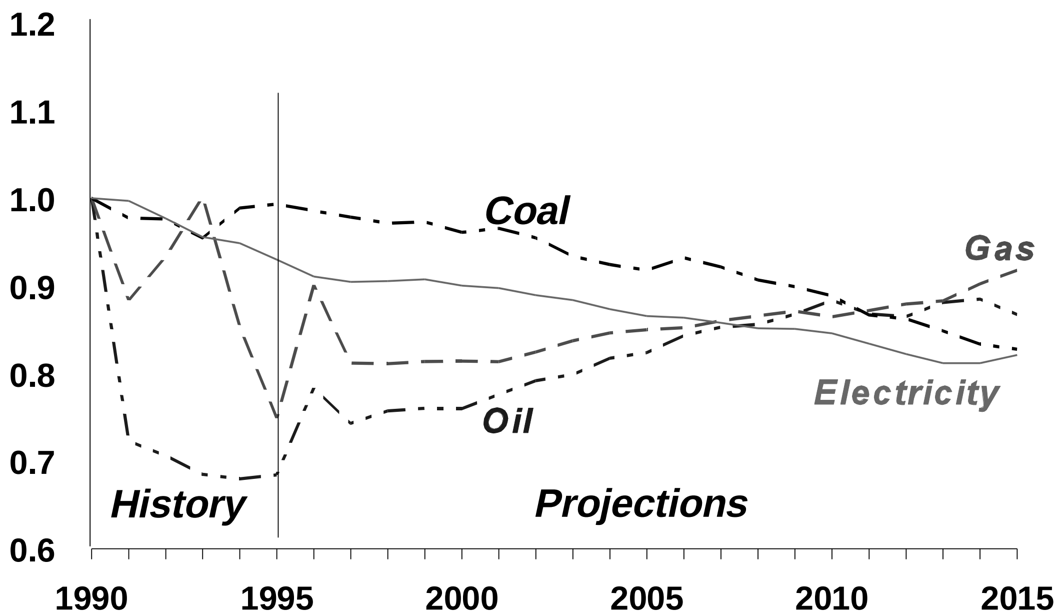


Figure 5. Fuel Prices to Electricity Suppliers and Electr Prices, 1990 - 2015 (Index, 1990 = 1.0)

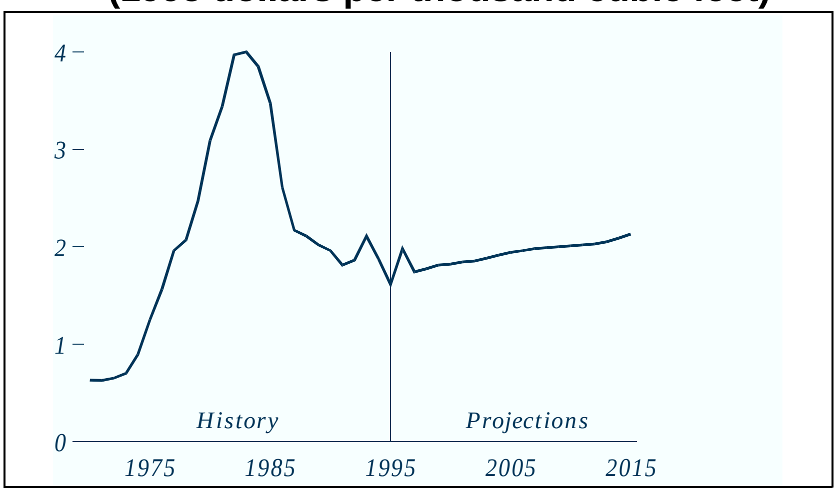


coal plants built are expected to be conventional pulverized coal plants with the remaining being integrated coal gasification plants (IGCC).[1]

II. Natural Gas, Coal, and Electricity Prices

Wellhead prices for natural gas in the lower 48 States increase by 1.4-percent annually in the reference case (Figure 6) reaching $2.13 per thousand cubic feet (in 1995 dollars) in 2015. The price increases reflect the rising demand for natural gas and its impact on the natural progression of the discovery process from larger and more profitable fields to smaller, less economical ones. In *AEO97*, technological progress arrests and even reverses declining finding rates in some regions. As a result, natural gas production is increased, with less drilling activity and at lower cost, particularly in offshore regions, where technological progress has a greater impact on the development of relatively immature fields. In addition, competition within the industry and projections of lower interest rates reduce the costs of transmission and distribution, offsetting the projected increase in wellhead prices, so that the average delivered price of natural gas declines between 1995 and 2015 at an average rate of 0.2 percent.

Figure 6. Lower 48 Natural Gas Wellhead Prices, 1970-2015
(1995 dollars per thousand cubic feet)

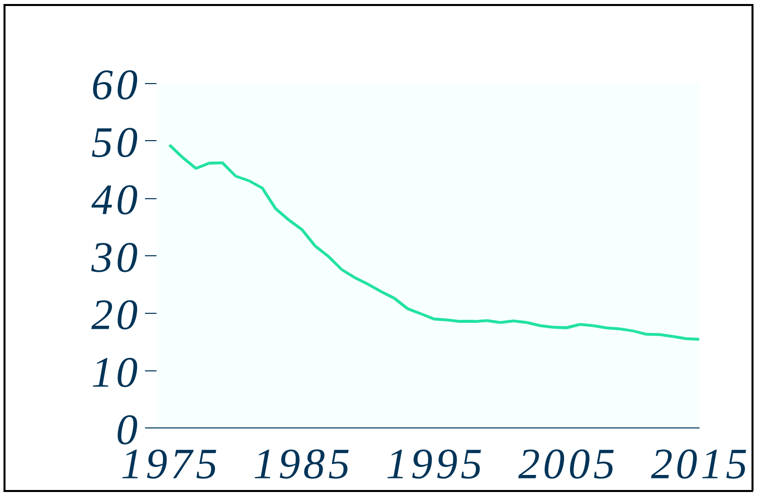


Coal minemouth prices are projected to decline in the forecast as a result of increasing productivity, a shift to western production, and competitive pressures on labor costs. In *AEO97*, the average minemouth price of coal is projected to be $15.46 per ton in 2015 (Figure 7). Lower coal transportation rates--leading to higher production from western mines, where production costs are lower than in the East--are the primary reason for the lower minemouth prices.

---

[1]The Electricity Market Module allows the representation of two coal technologies. The IGCC technology was used as representative of an advanced coal technology.

Figure 7. Coal Minemouth Price Projections, 1995-2015 (1995 dollars) (Dollars per ton)



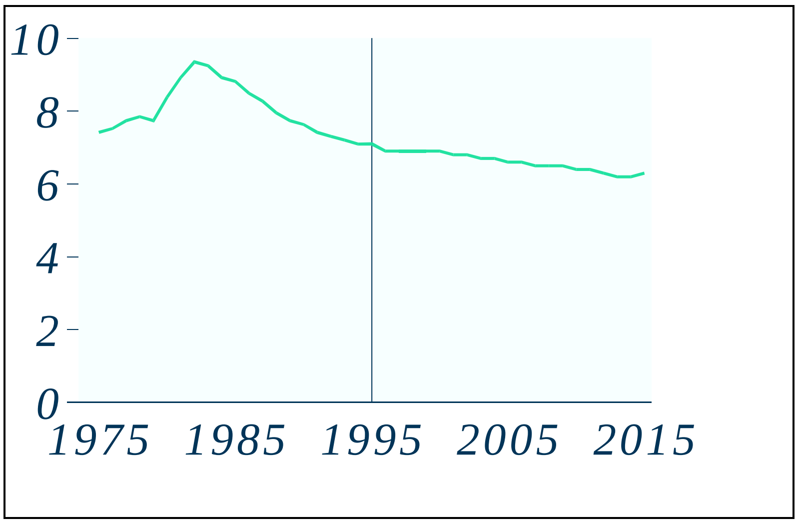
The competition between coal and other fuels, and among coalfields, is influenced by coal transportation costs. Changes in fuel costs affect transportation rates, but fuel efficiency also grows with other productivity improvements in the forecast. As a result, average coal transportation rates decline by 0.9 percent a year between 1995 and 2015. The most rapid declines are likely to occur in routes that originate in coalfields with the greatest production growth. Railroads are likely to reinvest profits from increasing coal traffic to reduce future costs and rates in regions with the best outlook. Thus, coalfields that are most successful at improving productivity and, therefore, lowering minemouth prices are likely to obtain the lowest transportation rates and, consequently, the largest markets at competitive delivered prices.

Regional differences in production and transportation costs are already affecting coal distribution patterns. Western coal is gaining share in midwestern and southeastern markets, and coal for export is moving along different domestic routes. Retirements of barge capacity have exceeded replacements in recent years, and the resulting increase in inland barge rates has caused some traffic to shift to rail or Great Lakes vessels for all or part of the journey from mines to U.S. ports of exit. In spite of railroad mergers and consolidation in the barge industry, real coal transportation costs are projected to continue their historical decline, as competition among surviving carriers forces technological improvements.

Average electricity prices also decline through 2015. The average price in 2015 is projected to be 6.3 cents per kilowatt hour, as a result of lower projected fossil fuel prices and anticipated industry restructuring (Figure 8). Increased competition in the electricity industry is assumed to lead to lower operating and maintenance costs, lower general and administrative costs, early retirement of inefficient units, and other cost reductions. The *AEO97* assumes that operating and

maintenance expenses decline by 2.5 percent annually from 1997 to 2007, continuing the trend of the previous 10-year period. Also, expenses charged to general and administrative functions (billing, salaries, and benefits) are assumed to drop by 25 percent during the same period as generators position themselves for increased competition. *AEO97* reflects the evolving trend of competition within electricity markets but does not include the full impacts of restructuring and deregulation. Although the projections include the recent actions taken by the Federal Energy Regulatory Commission on open access, specific actions to be taken by State public utility commissions and their timing are not yet known and have not been incorporated.

Figure 8. Electricity Price Projections, 1995-2015
(1995 dollars) (Cents per kilowatt hour)



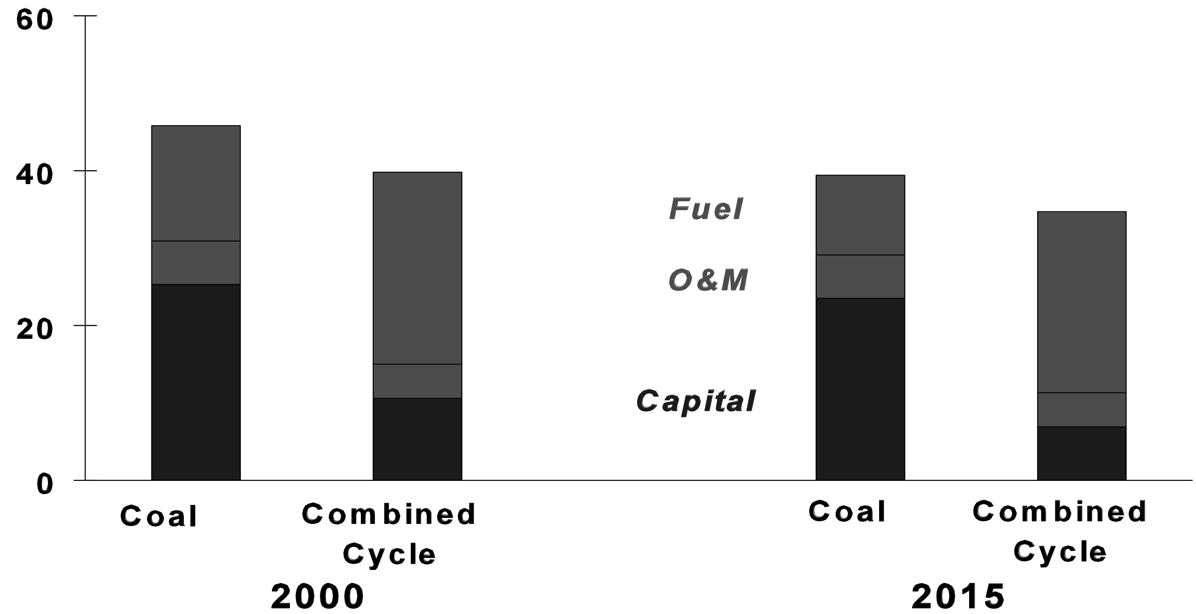
III. Economics of Coal versus Gas Technologies

The expected increasing reliance on gas-fired plants is driven by their economic competitiveness relative to other generating options. Over the last decade technological innovations in natural gas recovery and combustion have combined to lower expectations of future natural gas prices and dramatically increase the combustion efficiency of new gas plants. The result is that gas-fired plants are currently the economical choice for most applications. Figure 9 and Table 1 show the component costs of producing power from a pulverized coal plant and an advanced gas-fired combined cycle plant.[2] As shown the two technologies differ significantly in what drives their total levelized costs. Total coal plant costs are dominated by their capital costs while gas-fired combined-cycle plant total costs are dominated by fuel costs. Overall 55 to 60 percent of a coal plant total costs are related to its construction costs, while 62 to 68 percent of a gas combined-cycle plants costs are accounted for by fuel expenses.

Table 1. Costs of Producing Electricity From New Plants, 2000 and 2015

[2]The figures shown are nationwide averages. In some regions coal is more competitive while in others it is less competitive.

Figure 9. Levelized Cost of Electricity, 2000 and 2015 (Mills per Kilowatthour)



	2000	2000	2015	2015
	Conventional Pulverized Coal	**Advanced Combined-Cycle**	**Conventional Pulverized Coal**	**Advanced Combined-Cycle**
	1995 mills per kilowatt hour			
Capital	25.3	10.6	23.5	6.9
O&M	5.6	4.4	5.6	4.4
Fuel	14.9	24.8	10.3	23.4
Total	**45.8**	**39.9**	**39.4**	**34.5**
	Btu per kilowatt hour			
Heatrate	9,928	6,985	9,463	5,700

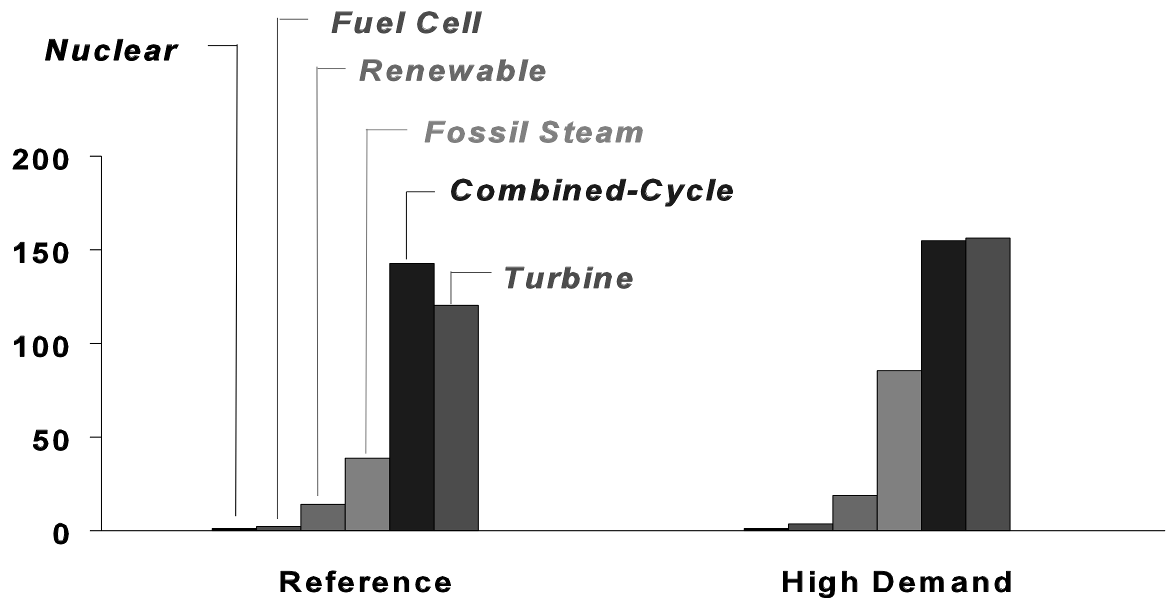
IV. Uncertainties and Impacts of Electricity Market Restructuring

Among the uncertainties with respect to the size of the market for new coal powerplant technologies are the rate of growth of the demand for electricity, the prices of competing fuels, especially natural gas and the rate of technological innovation (improvements in the cost and performance of advanced generating technologies). The restructuring of the electricity market could also have a significant impact, but its impact would affect the demand for electricity and fuel prices. While the rate of growth in the demand for electricity has slowed over the last 30 years, over the last 15 years it has averaged 2.4 percent per year. It is expected that the long-term slowing will continue, but it is possible that new electricity uses, tomorrow's VCRs, fax machines, and computers, will continue to evolve and maintain the rate of growth seen in recent years. To test the sensitivity of the results to higher electricity demand growth a case was prepared assuming a rate of growth in the demand for electricity of 2.0 percent annually, much higher than the 1.5 percent annual growth rate in the reference case. The impact on the need for new capacity is large, over 100 gigawatts of capacity beyond that required in the reference case is brought on line (Figure 10). The higher demand growth increases the market for all capacity types, but coal plants gain the most. Between the reference case and the high demand case the amount of new coal plants added more than doubles, reaching a cumulative total of over 80 gigawatts between 1995 and 2015. The reasons for this are twofold. First, the higher demand level increases the total need for new capacity. And, second, the higher demand level has a stronger impact on natural gas prices than it does on coal prices making new coal plants relatively more economically attractive.

If, as many expect, the restructuring of U.S. electricity markets results in lower electricity prices the demand for electricity is likely to be somewhat higher, though how much is unclear. However, this may not result in increased needs for capacity. The need for capacity is determined by the highest demand for electricity occurring during a given period, the so called peak demand. Prices during these supply constrained time periods may actually be much higher in a restructured electricity market than they are today and consumers may respond by reducing their consumption during these time periods while increasing it in lower cost time periods. The net result of this shifting demand could be increasing utilization of existing lower cost facilities, but a reduction in the need for new capacity for some time.

Two additional cases were prepared to assess the sensitivity of the results to the rate of technological improvement. In the reference case, higher initial capital costs are assumed for new, advanced generating facilities, to account for both technological optimism and inexperience in constructing the new designs. The costs are assumed to decline as a function of market penetration. To examine the effects of these assumptions, a high technology case was developed, with capital cost reductions due to learning effects assumed to be 50 percent greater than in the reference case, and optimism factors (which increase the cost of the earliest units constructed) assumed to be 50 percent lower than in the reference case. These assumptions result in costs for advanced technologies being approximately 12 percent lower than in the reference case. A low technology case was also prepared assuming that only those technologies available (beyond the initial testing and pilot program phase) as of 1996 are permitted to compete. The most

Figure 10. New Generating Capacity by Fuel Type in Two Demand Cases, 1995-2015 (Gigawatts)



significant result between the low and high technology cases is the shift from conventional gas-fired technologies to advanced gas-fired technologies (Figure 11). Advanced coal and renewables plants only penetrate by small amounts.

Two alternative *AEO97* analyses--the high and low nuclear cases--show how changing assumptions about the operating lifetimes of nuclear plants affect the reference case forecast of nuclear and fossil capacity. The low nuclear case assumes that, on average, all units are retired 10 years before the end of their 40-year license periods (93 units by 2015). Early shutdowns could be caused by unfavorable economics, waste disposal problems, or physical degradation of the units. The high nuclear case assumes 10 additional years of operation for each unit (only 4 units retired by 2015), suggesting that license renewals would be permitted. Conditions favoring that outcome could include continued performance improvements, a solution to the waste disposal problem, or stricter limits on emissions from fossil-fired generating facilities. In the low nuclear case, more than 100 new fossil-fueled units (assuming an average unit size of 300 megawatts) would be built to replace retiring nuclear units. The new capacity would be split mainly between coal-fired (37 percent) and combined-cycle (47 percent) units. The additional fossil-fueled capacity would produce 43 million metric tons of carbon emissions above those in the *AEO97* reference case, in 2015 (1,799 million metric tons total, 678 million metric tons from electric generators). Also, 3 gigawatts of additional new renewable and fuel cell capacity would be built. In the high nuclear case, 32 gigawatts of new capacity additions--mostly fossil-fueled plants--are avoided, as compared with those in the *AEO97* reference case, and carbon emissions are reduced by 29 million metric tons (4 percent of total emissions by electricity generators).

Figure 11. Unplanned Capacity Additions in Three Technology Cases, 1995-2015 (Gigawatts)

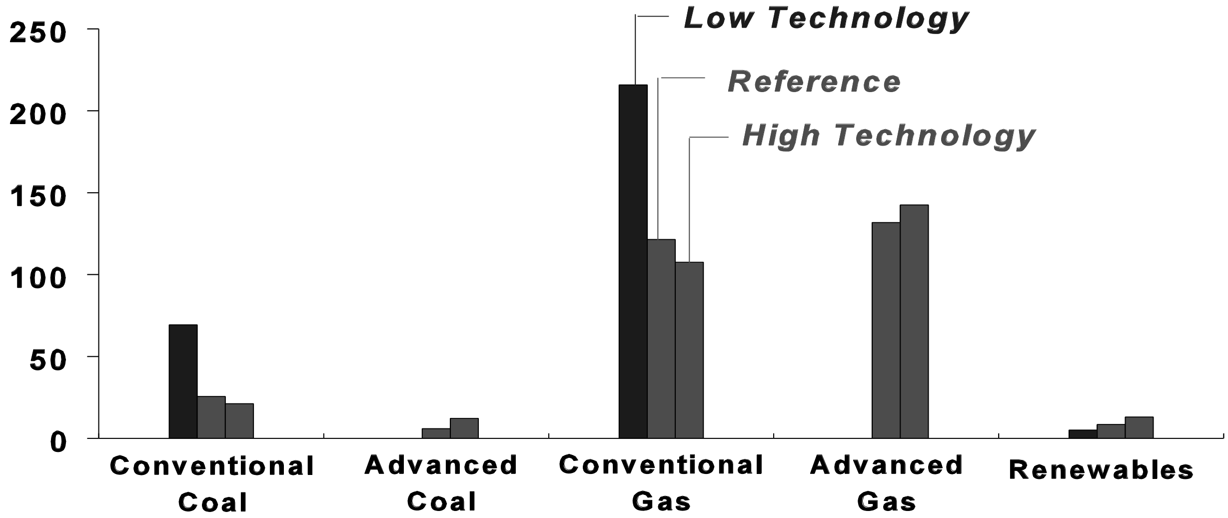
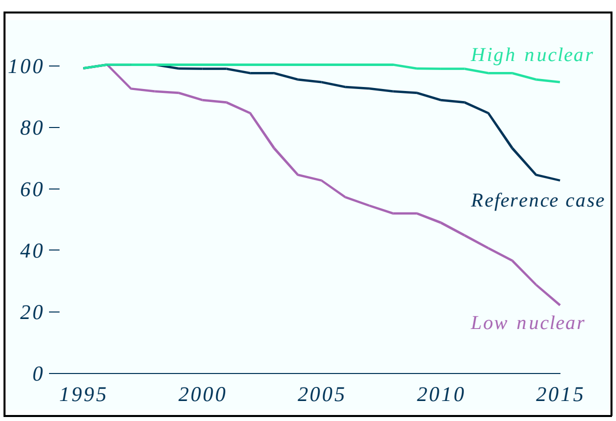


Figure 12. Operable Nuclear Capacity in Three Nuclear Cases, 1995-2015 (Gigawatts)



V. Conclusions

Over the next 10 to 20 years natural gas-fired generation technologies are expected to meet most of the needs for new capacity. Their relatively low capital costs, high thermal efficiencies and low emissions rates make them very attractive. New coal fired technologies are expected to account for around 11 percent of new capacity added, though that number could be larger if the demand for electricity or natural gas prices prove higher than expected. The major market of new clean coal technologies in the U.S. may be in retrofitting or repowering existing plants to meet new environmental requirements.

Figure Notes

Figure 1. Population, Gross Domestic Product, and Electricity Sales Growth, 1960-2015
History: Energy Information Administration, *Annual Energy Review* 1995, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections**: *Annual Energy Outlook* 1997, Tables A8 and A20.

Figure 2. Annual Electricity Sales by Sector, 1970-2015
History: Energy Information Administration, *Annual Energy Review* 1995, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections**: *Annual Energy Outlook* 1997, Table A8.

Figure 3. New Generating Capacity and Retirements, 1990-2015
Annual Energy Outlook 1997, Table A9.

Figure 4. Electricity Generation and Cogeneration Capacity Additions by Fuel Type, 1995-2015
Annual Energy Outlook 1997, Table A9.

Figure 5. Fuel Prices to Electricity Suppliers and Electricity Prices
History: Energy Information Administration, *Annual Energy Review* 1995, DOE/EIA-0384(95) (Washington, DC, July 1996). **Projections**: *Annual Energy Outlook* 1997, Tables A3 and A8.

Figure 6. Lower 48 Natural Gas Wellhead Prices, 1970-2015
Annual Energy Outlook 1997, Table A1.

Figure 7. Coal Minemouth Fuel Price Projections, 1995-2015
Annual Energy Outlook 1997, Table A1.

Figure 8. Electricity Fuel Price Projections, 1995-2015
Annual Energy Outlook 1997, Table A8.

Figure 9. Levelized Cost of Electricity, 2000 and 2015
Annual Energy Outlook 1997, National Energy Modeling System, run AEO97B.D100296K.

Figure 10. New Generating Capacity by Fuel Type in Two Cases, 1995-2015
Annual Energy Outlook 1997, Tables A9 and F6.

Figure 11. Unplanned Capacity Additions in Three Cases, 1995-2015
Annual Energy Outlook 1997, Tables A9 and B9.

Figure 12. Operable Nuclear Capacity in Three Cases, 1995-2015
Annual Energy Outlook 1997, Table F5.

THE ROLE OF CLEAN COAL TECHNOLOGIES IN A DEREGULATED RURAL UTILITY MARKET

John W. Neal
Director of Research
National Rural Electric Cooperative Association
4301 Wilson Boulevard
Arlington, VA 22203

ABSTRACT

The nation's rural electric cooperatives own a high proportion of coal-fired generation, in excess of 80 percent of their generating capacity. As the electric utility industry moves toward a competitive electricity market, the generation mix for electric cooperatives is expected to change. Distributed generation will likely serve more customer loads than is now the case, and that will lead to an increase in gas-fired generation capacity. But, clean low-cost central station coal-fired capacity is expected to continue to be the primary source of power for growing rural electric cooperatives. Gasification combined cycle could be the lowest cost coal based generation option in this new competitive market if both capital cost and electricity production costs can be further reduced. This paper presents anticipated utility business scenarios for the deregulated future and identifies combined cycle power plant configurations that might prove most competitive.

I. NRECA and RER

NRECA is the national trade association representing the nation's nearly 1000 consumer-owned electric cooperatives. Recognizing the importance of science and technology to the success of its electric cooperative members, NRECA administers a research and development program for its member systems known as the NRECA Rural Electric Research (RER) Program. RER is voluntarily funded by participating member cooperatives at approximately $4.5 million annually. RER works closely with EPRI and other utilities to ensure that industry-wide technology developments may be applied to the unique needs of rural electric systems in a cost-effective manner.

II. UNIQUENESS OF ELECTRIC CO-OPS

Electric cooperatives, for the most part, serve sparsely populated rural and agricultural areas of the U.S., representing some of the nation's least developed and roughest terrain. Even so, co-ops sell about 7.5% of the nation's power to 30 million consumers in 46 states, and own nearly half of the distribution line miles in the country in order to deliver this power to their consumers. Co-ops average about five consumers per mile of line compared to the rest of the electric utility industry's average of around 40 customers per mile. Since electric revenue is a direct function of customer density, providing economical electric services to rural consumers is a challenge. This is complicated by the fact that much of rural electric load growth occurs at the end of long feeders. Thus, expensive transmission and distribution right-of-ways must be acquired in order to upgrade or provide new lines for increased power supply to these locations via conventional central station service.

III. CO-OP POWER SUPPLY TODAY

Currently, nearly one-half of electric cooperative power needs are provided by 60 generation & transmission (G&T) cooperatives. These G&T cooperatives are owned by the distribution cooperatives they serve. From an operational point of view, rural electric generation facilities are not very different from the rest of the utility industry. Where co-ops are different is that they own a high proportion of coal-fired generation, in excess of 80 percent of their generating plant capacity. Co-op generating facilities are environmentally the cleanest in the industry because they are the newest. Forty-four percent of the co-op coal-fired capacity already has flue gas scrubbers compared to 20 percent nationwide. All together, co-ops own or have ownership in 11 of the nation's lowest-cost power producers.

IV. DEREGULATION

NRECA and its member systems have actively participated in the policy deliberations involving deregulation of the nation's electric utility industry. Chief among the possible changes anticipated is the "unbundling" of the services performed by what has historically been a vertically integrated industry. Unbundling proposals could separate the electric utility industry into four distinct components: generation, transmission, distribution and energy services.

Generation Company (GENCO)

The generation part of the business will in all likelyhood compete in an open wholesale market. Restructuring advocates often propose that the generation component of an electric utility's business be sold to an independent company or spun off to a separate unregulated utility affiliate, a GENCO. The power would be sold at whatever price the seller could obtain in the generation market at a given time—known as a *market-based* rate. This means that power rates would not be *cost-based* on what it took to produce the power, but rather only the price the power could command in the marketplace.

Transmission Company (TRANSCO)

Transmission, following the finalization of Federal Energy Regulatory Commission (FERC), Orders Nos. 888 and 889, will be an open access system. Restructuring proposals often call for the transmission component of an electric utility's business to be given to a separate regulated TRANSCO, or even handed off to an "Independent System Operator" (ISO). Most proposals would continue regulation of transmission, on the assumption that it is unlikely for substantial competition to develop in the transmission sector. This is due to the difficulties and high costs of building transmission lines, getting rights of way and obtaining needed environmental and land-use clearances. Since bulk transmission lines often transmit power that comes from other states, plans call for FERC to regulate the price for and terms of transmission services.

Distribution Company (DISCO)

Under many restructuring proposals, the distribution component would be handed by a separate regulated distribution company, called a DISCO. Like transmission, most proposals would continue the regulation of DISCOs, because of the high cost of building duplicate distribution lines, and the aesthetic/environmental constraints. Virtually, all plans call for state regulation of DISCOs.

However, DISCOs would not necessarily perform all of the functions that we currently think of when we think of electric distribution companies. Many proposed DISCOs would carry out a pure *wires* (electricity delivery) function. The actual sale of electricity at retail is generally proposed to be open to competition. Retail customers would pick their electric power supplier just like they now pick their long-distance telephone service provider. This separation of the *wires* functions from the actual sale of the power is the essence of *retail wheeling, retail access,* and *customer choice,* terms we have all heard as part of the restructuring debate. Retail access is at the heart of the restructuring debate. Restructuring advocates want retail customers to be able to purchase their electric power from any one of a number of suppliers, with the power being transmitted and delivered by an entity distinct from the supplier. For the utility that owns the DISCO to compete for actual electricity sales to retail customers, it would have to form its own separate marketing entity, and that entity would have to use the DISCO for delivery service, just like any other supplier.

Energy Service Company (ESCO)

Retail electric distribution service may be split up into a number of parts: *delivery, retail sales,* and *energy services.* Retail sales could be made by generators, marketers, brokers, aggregators of all sorts. The providers and types of energy services are just beginning to emerge. Some envision separate energy service companies (ESCOs) that would become the marketers of a wide-range of services such as purchasing electricity from power producers, repackaging the electricity with valued-added consumer services and seeking out markets in which compete.

V. IMPACT OF DEREGULATION

These potential changes will have a substantial impact on every aspect of the electric utility business. A broadly-based task force drawn from NRECA's membership studied the likely industry changes and recently issued an initial report on the resulting competitive issues. The task force arrived at five conclusions that will receive a great deal of attention from electric cooperatives and may have implications for the entire industry. These are felt to be valid regardless of how the industry finally restructures:

- Customers will have their choice of an energy provider;
- There will be increasing pressure to regulate all distribution operations;
- The future of all power supply arrangements is unclear;
- The advantage of electric co-ops is their strong relationship with consumers;
- Future success requires being competitive on price, service and reliability.

Even though the final industry restructuring is not yet known in detail, one can draw certain general conclusions about the four proposed utility functions that may evolve:

Transmission

This part of the business will be regulated as an open access network by the federal government through FERC. The past decade has seen a four-fold increase in bulk power transfers across the country. Now, 40% of the electricity generated in the U.S. is sold by the producing utility on the bulk power market before it reaches consumers. Such wholesale transactions, which involve electricity transfers over transmission networks, are expected to increase significantly because of federal deregulation producing open access to the networks. Transmission systems, for example, now experience loads at 70% or more of their capacity less than 20% of the time. For distribution systems, the corresponding capacity utilization occurs less than 5% of the time. Thus, there appears to be adequate capacity to handle the increased transactions that might result from deregulation. But technology is expected to be able to accomodate substantially greater power transfer capability over existing systems if needed.

Distribution

This part of the business will likely be regulated by the states. There is a consensus that it does not make sense for multiple wires and service entrances to be installed depending upon who you elect to provide your power. As a result, regulations will be necessary to compensate the one *wires* company delivering power, while preventing monopolistic pricing policies that would be unfair to the customer. While state-level deregulation will give consumers greater choice among electricity providers, at the same time, consumers are increasingly concerned about the power quality. Momentary disturbances that would have gone unnoticed in the past will become a major concern in the future, causing computers and other digital equipment to malfunction (i.e., the “blinking clock syndrome”). As a result, successful DISCOs will be those that deliver high-quality power at low cost and follow it up with excellent customer service.

Energy Services

ESCOs would likely be unregulated entities competing in the marketplace to provide power to customers. ESCOs would be able to buy bulk power and resell it to consumers along with additional services, or provide distributed generation at or near a customer site. In either case, economics will dictate the choice of generation selected by the ESCO for a particular application. Some predict distributed generation to be as much as 30% of new electric generation by 2010. If true, that would be more than 50 gigawatts of the 175 gigawatts of generation growth that the U.S. Energy Information Administration (EIA) expects by then. NRECA believes distributed generation will be a valuable power supply option for servicing many rural customer loads. But, the electric co-ops see a much more modest growth in distributed generation by 2010, probably not exceeding 5 to 10 percent of total generation expansion, if that much.

Generation

Although FERC and others are still working out the details, it appears likely that the generation part of the business may ultimately become totally deregulated and truly compete on the open market to sell the electricity it produces. This power will be sold as a commodity like oil or corn. In fact, electricity futures markets are already being formed in anticipation of the public buying and selling bulk electricity transactions just as is the case with other commodities.

In such a marketplace, only the low-cost providers survive. Unlike ESCOs that will provide distributed generation at a premium cost level of perhaps 4 to 5 cents/kWh or more along with services to solve a customer problem, GENCOs will sell bulk power strictly on the basis of what the market will pay for this commodity. Average power production costs in the U.S. dropped below 2 cents/kwh for the first time since 1981 according to the Utility Data Institute. So it is reasonable to assume that the production cost threshold could be around 2 cents/kWh or less in order to successfully compete with bulk power sales in the new electricity marketplace. Thus, decisions to build new central station power plants in the future will be based on three criteria:

- Cost of electricity;
- Short construction lead time;
- Flexibility of the technology to achieve performance and cost goals in plant sizes ranging from 100 mW to over 1000 mW;
- The ability of the technology to meet ever-tightening environmental requirements without significant additional capital costs.

NRECA sees a continuing important role for coal in the new generation business. Central station power has the capability to achieve the low cost of electricity that the new marketplace will demand. And domestic coal reserves will provide the long-term low-cost fuel that can make this possible. However, the economics of scale of central station facilities is essential for coal plants to realize low-electricity production costs.

VI. TOMORROW'S COAL-FIRED POWER PLANTS

A consensus exists in the rural electric program that new central station power plants will generally be smaller than in the past. A few hundred megawatts will be more typical than a thousand megawatt or more. And modular plants offering short construction lead times and consistent performance over a range of sizes will dominate.

Although the generation part of the utility business will likely be unregulated and compete in the open market for electricity sales, from the environmental point of view, it will continue to be strictly regulated.

Hundreds of pages of regulations have been drafted to implement power plant SOx and NOx reductions required under the nation's 1990 Clean Air Act. Now, in 1996, the legislative and regulatory focus has shifted to reduce the output of CO2 and other "greenhouse gases," which some scientists believe are causing global warming.

Too, solid waste from power plants is increasingly the focus of proposed regulations under such legislation as the Endangered Species Act, the Clean Water Act, the Toxic Substances Control Act, the Resource Conservation and Recovery Act, and the Comprehensive Environmental Response Compensation and Liability Act - better known as Superfund.

The evolutionary development process leading to vast improvements in coal-fired central station power plants began in the 1960s with the development of fluidized-bed boilers. Atmospheric fluidized-bed (AFB) and pressurized fluidized-bed (PFB) boilers were seen as a potentially better way for utilities to burn virtually all ranks of coal directly while meeting the old 90 percent sulfur-removal requirements of the nation's first Clean Air Act. While direct combustion of coal via fluidized-bed boilers offers many advantages and will continue to be an important power plant option in many parts of the country, NRECA believes that coal gasification offers more advantages than direct combustion for the long-term highly competitive utility generation market.

Integrated Coal Gasification Combined Cycle (IGCC)

Coal gasification, in combination with new advanced power conversion technology such as high temperature turbines and fuel cells, clearly holds the key to central station coal-fired power plants that can compete in the bulk power generation market of the future.

In the early 1980s, ground was broken for the nation's first IGCC power plant at Southern California Edison's Coolwater site in Daggett, CA. This fundamental change in research direction away from direct coal combustion toward coal gasification was in recognition of the greater potential that coal gasification offered in terms of overall environmental performance and costs.

With direct coal combustion, impurities such as sulfur compounds and particulates must be cleaned from the post-combustion gas stream. The key advantage of IGCC is that gasification changes the fuel form from a solid to gasified coal which enables the impurities to be removed before combustion.

In the 100 mW Coolwater demonstration plant, a coal-water slurry was gasified in the presence of oxygen using a Texaco gasifier. The hot raw gas was cooled down, ash particles and other carry-over were scrubbed from the mixture, and then sulfur was chemically stripped from the gas.

The end product was a clean gaseous coal-derived fuel burned in a combustion turbine to produce electricity. Waste heat from the turbine exhaust was recovered to produce additional electrical power through a steam turbine.

And now, in the late 1990s, the U.S. Department of Energy, along with continuing electric utility industry R&D, has made significant progress toward demonstrating major improvements to the basic IGCC cycle

that could usher in coal gasification combined-cycle as the standard central station power plant for the next century.

An IGCC plant based upon the Coolwater configuration could be built today to operate on high-sulfur coal while emitting fewer pollutants than a comparable sized oil-fired power plant. But, the technology has improved from the Coolwater design at a significant rate due to advances being demonstrated under DOE's Clean Coal Technology program. The advanced IGCC system soon to enter demonstration testing at Sierra Pacific Power in Nevada will validate a number of these important advances. Technologies in Sierra Pacific's IGCC such as the pressurized fluidized-bed coal gasifier with in-bed desulfurization and full-stream hot gas cleanup, along with the use of a new generation of high-firing temperature combustion turbines, are critically important steps toward achieving the reduced electricity production costs that will be necessary to compete in the new competitive bulk power market.

Integrated Gasification Humid Air Turbine (IGHAT)

Further improvements to reduce the capital cost of IGCC plants will also be needed to ensure their success in this new competitive market. One approach to lower the cost of an IGCC power plant is to eliminate or perhaps simplify the equipment that is used to recover waste heat from the turbine exhaust and generate additional electricity. EPRI research on IGCC has been focused on how the waste heat could be recovered and expanded through the primary gas turbine power source instead of requiring a separate steam turbine to generate the additional electricity.

Under an EPRI research contract, engineers at Fluor Corporation identified a promising new concept for recovering the exhaust heat. Rather than having air pass directly from the compressor stage of a gas turbine into the combustion stage, this process diverts it into a cooler and then into a vessel known as a saturator. After the compressed air enters the bottom of the saturator, it flows upward against a stream of water that has been heated by the turbine exhaust, the compressed-air cooler, and any other sources of low-level heat. When the air leaves the top of the saturator, it has been humidified to between 10 percent and 40 percent water vapor. This humidified air is then further heated by the turbine exhaust and sent to the combustor, where fuel is added and burned.

In the process, the power produced by a gas turbine expander is proportional to the density of the combustion products that are being expanded. So, by substantially humidifying the air going into the combustor, the density of the combustion stream is greatly increased. Thus, the power extracted by the turbine expander is proportionally increased, thereby producing much more electricity from the gas turbine generator. As a result, a power plant based on a coal gasifier and this turbine could have a heat rate as low as 8,500 Btu/kWh (over 40 percent efficiency) without using a steam bottoming cycle but still reclaiming low-level heat that would be difficult for other cycles to utilize.

In addition, use of the IGHAT cycle could help lower the capital cost of a gasification-based power plant by nearly 20 percent compared with the Coolwater IGCC approach. The reason is that in an IGCC plant, heat for raising steam is obtained by passing the coal gas through large coolers, which are the most expensive components of the gasification system. With the IGHAT cycle, the gas could simply be quenched with water.

A prototype of this turbine has not yet been constructed. But because of the relative simplicity of the IGHAT cycle, and the fact that it is based on current component technology, EPRI believes it could be fully commercialized by 2003.

Integrated Gasification Fuel Cell (IGFC)

An even more dramatic improvement to the coal gasification power plant involves eliminating the combustion turbine altogether and using a fuel cell to convert the coal gas directly to electricity through an electrochemical process. Such direct conversion potentially offers the highest efficiency and lowest emissions of any coal-based plant yet devised.

The integrated fuel-cell coal-gasification power plant, which could be commercially available by approximately 2010, might represent the final step in the nation's quest for clean coal technology. This system could potentially offer the following operational advantages:

- Virtually no SOx and NOx emissions, even with the very highest-sulfur U.S. coals;
- Modularity that lends itself to short construction lead times;
- A capital cost comparable to today's best technology, a new pulverized-coal-fired (PC) power plant with flue gas scrubbers;
- A 20 percent reduction in the bus-bar cost of electricity compared to today's PC plant with scrubbers; and
- A full 30 percent reduction in heat rate - which translates to a 30 percent reduction in CO2 discharge, should that become required as U.S. policy develops on global climate change.

Ideally the fuel cell selected for use with a coal gasification unit should operate at about the same temperature as the gasifier. The most promising candidate is a fuel cell using a molten carbonate electrolyte. The molten carbonate fuel cell (MCFC) technology has been operated successfully on gasified coal. Moreover, it is now operating in a 2 mW electric utility demonstration plant at Santa Clara Municipal Utility in Southern California, and it is being accelerated into commercialization by the electric utility industry's Fuel Cell Commercialization Group (FCCG).

An MCFC produces electricity directly from either gasified coal or natural gas fuel and air without a combustion process. An electrochemical reaction takes place between the hydrogen from the fuel and the oxygen from the air in a closed container, with the molten carbonate electrolyte maintained at 1200°F.

This reaction produces electricity in a manner resembling a battery. It makes no noise. The byproducts are pure water and carbon dioxide.

The first integrated gasification fuel cell cycle will likely be achieved by substituting a molten carbonate fuel cell for the gas turbine in the standard IGCC plant. This alone is predicted to offer a significant improvement in heat rate from 8,900 Btu/kWh down to 7,500 Btu/kWh, with a slight reduction in bus-bar electric costs.

But the big improvement is realized when the molten carbonate fuel cell is "chemically integrated" with the coal gasifier. With this approach, the heat rate of the IGFC plant could be further lowered down to 6,000 BTU/kWh, achieving a coal-pile-to-bus-bar efficiency approaching 60 percent, compared with about 37 percent for today's best pulverized-coal technology.

Chemical integration, the key to such attractive performance, involves configuring the system in a manner such that the fuel cell's unconverted fuel and the fuel's heat content is recycled back into the gasifier. A special methane-producing gasifier would be required to maximize the chemical content of the coal-derived gas. Also, a hot gas clean-up step would be employed to clean the coal gas for use in the fuel cell without first cooling it down.

These are, of course, engineering developments that would have to take place successfully before such an advanced IGFC could be commercialized. But these are just engineering problems to be solved, and do not require any scientific breakthrough to achieve. As a result, EPRI believes this promising IGFC plant could become a commercial reality by 2010. If so, it could truly represent the final developmental step in the quest for clean coal-power generation.

VII. CONCLUSIONS

Deregulation of the electric utility industry would result in many changes to the way business is done today. In the unregulated, market-driven GENCO and ESCO businesses, electricity sales will be dominated by the low-cost providers.

ESCOs could successfully capture up to about 10 percent of the 175 gigawatts of new U.S. capacity needed by 2010 with dispersed generation. Dispersed generation electricity costs will be able to bear a premium above central station bulk power generation because the ESCO customers will be provided additional value-added services. Also, distributed generation will realize some payback from deferred transmission or distribution construction.

Central station power plants are expected to continue to provide the major portion of the nation's new bulk power needs. But only very competitive low-cost generating stations will be constructed. These will

likely be built in smaller increments of 100 mW or so compared to today's larger plants.
Coal will continue to be a major factor in central station bulk power generation. And the economics and environmental performance of coal gasification combined cycle power plants will likely position this option as the dominate technology for coal fired central station generation.

DOE's clean coals technology program has been a major factor in bringing coal gasification combined cycle power plants to commercial readiness. Without this promising option, the nation's abundant coal resource might not continue to be in demand in competitive utility markets where low-cost dominates but emission regulations continue to tighten. But further progress on capital cost reduction and performance improvement is essential to ensure coal's long-term place in such a market.

5th ANNUAL CLEAN COAL TECHNOLOGY CONFERENCE

Remarks of
Brian J. McLean, U.S. EPA

January 9, 1996
Tampa, Florida

ENVIRONMENTAL CONCERNS

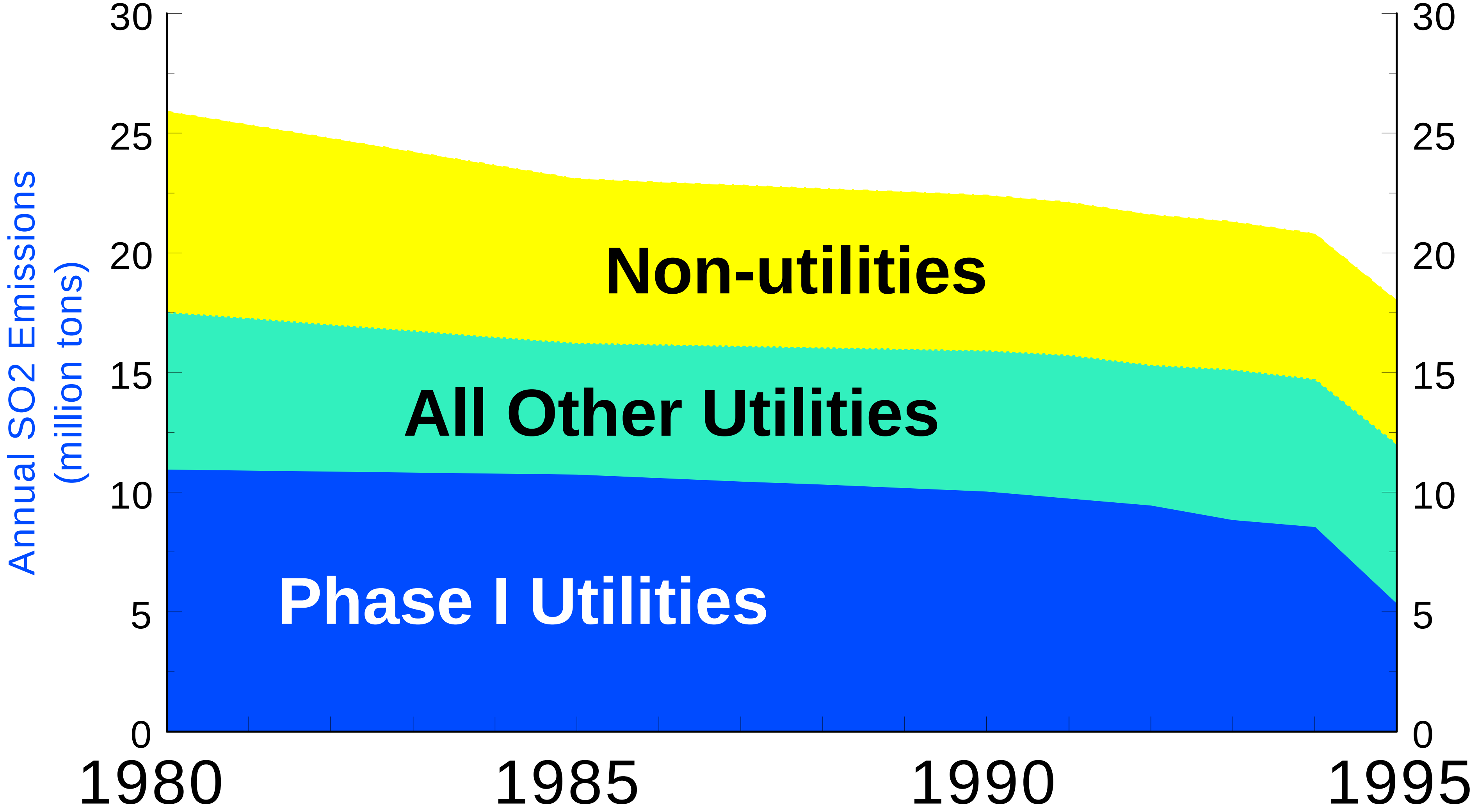
Public Health	Environment
Ozone	Acidification
Fine Particles	Eutrophication
Toxics	Materials Damage
	Crop/Forest Damage
	Visibility/Regional Haze

Climate Change

GOAL OF TITLE IV

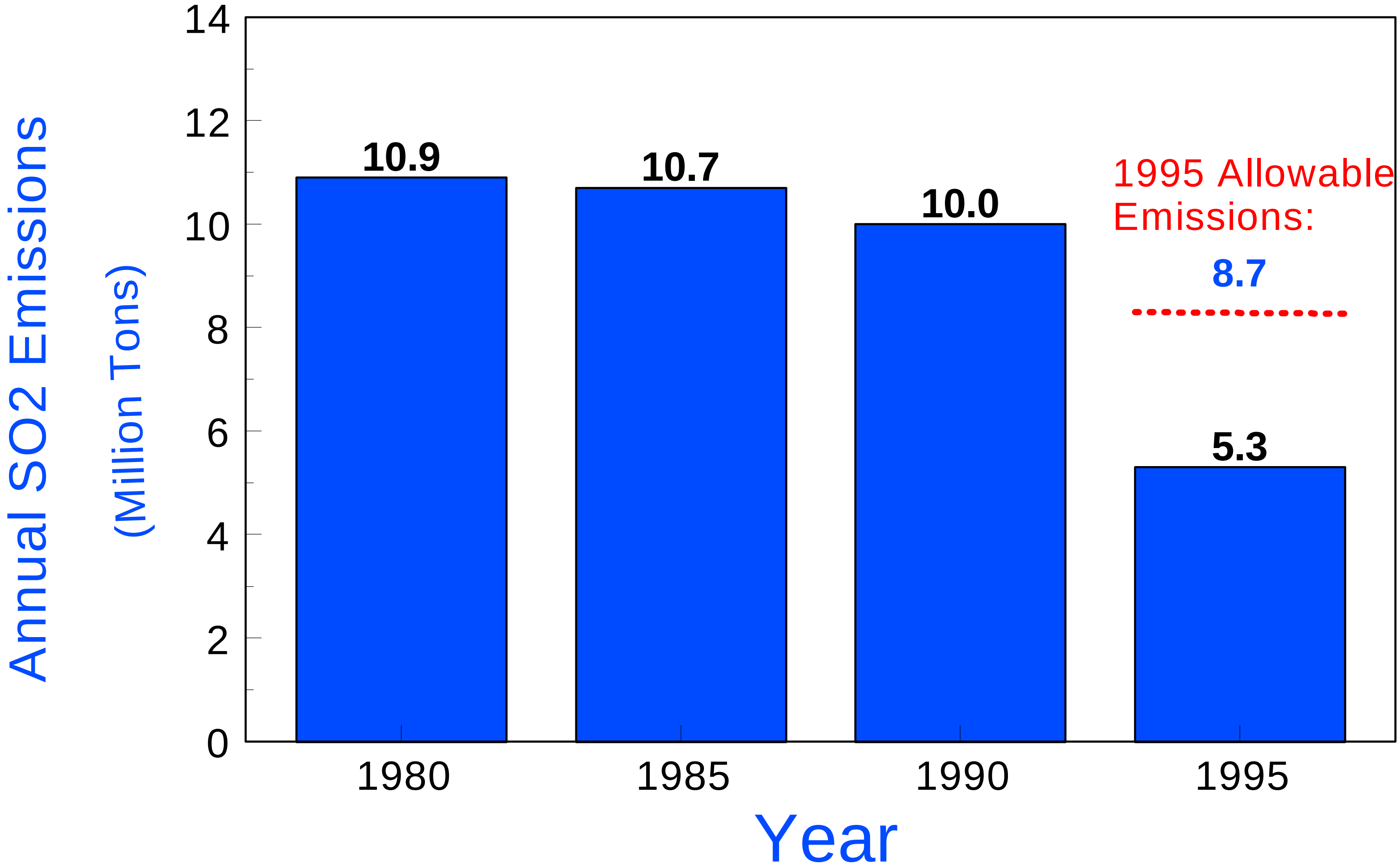
To reduce SO_2 and NO_x from power generation as cost-effectively as possible in order to protect public health and the environment

NATIONAL SO2 EMISSIONS
All Sources



SO2 Emissions

445 Phase I Affected Utility Units



REDUCTIONS IN WET SULFATE DEPOSITION

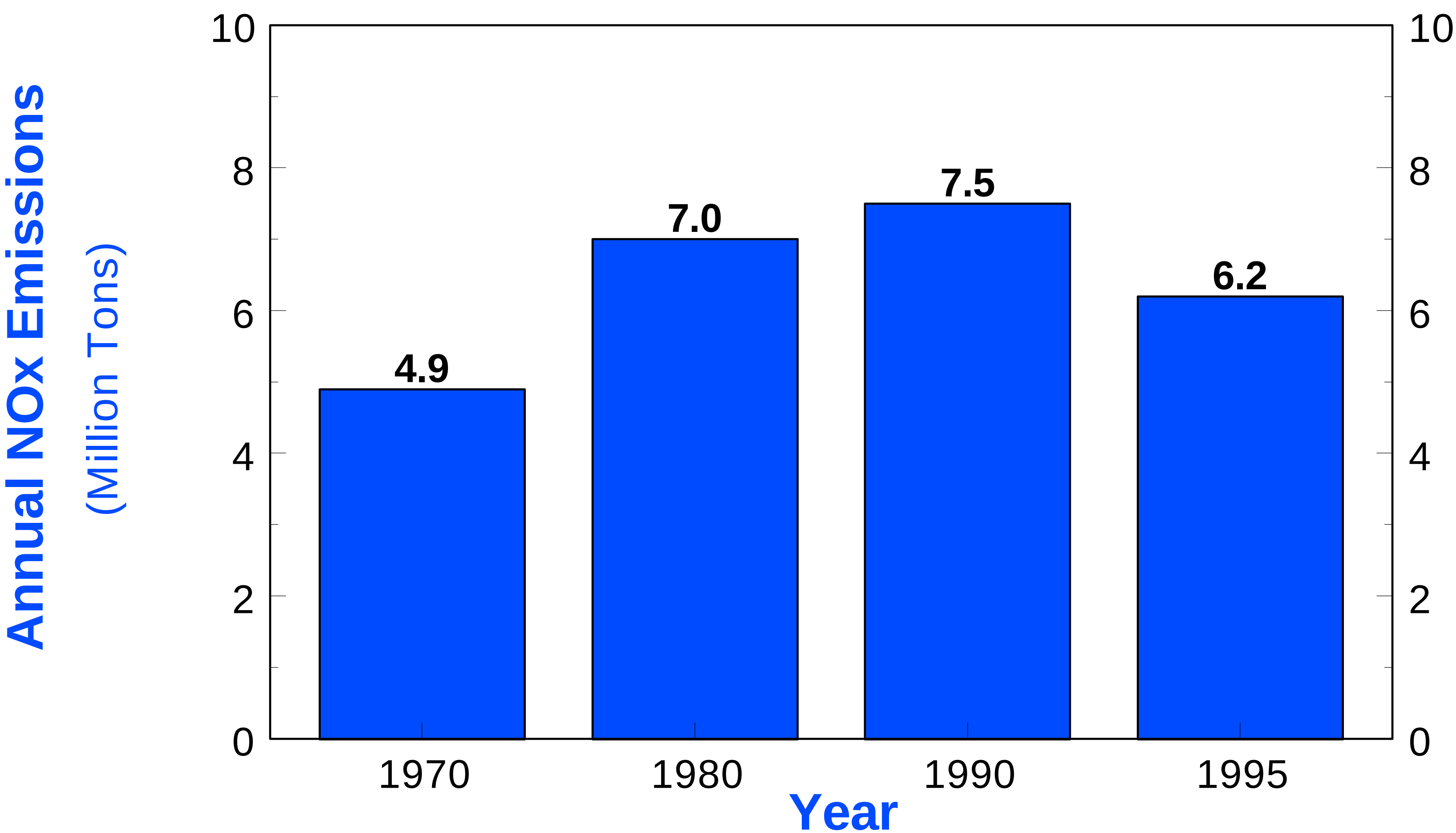
SO2 ALLOWANCE PROGRAM: BENEFITS

- Health: $12 - 40 billion per year by 2010
- Visibility: $3.5 billion per year by 2010
- Fewer acidic lakes & streams
- Reduced damage to buildings & monuments

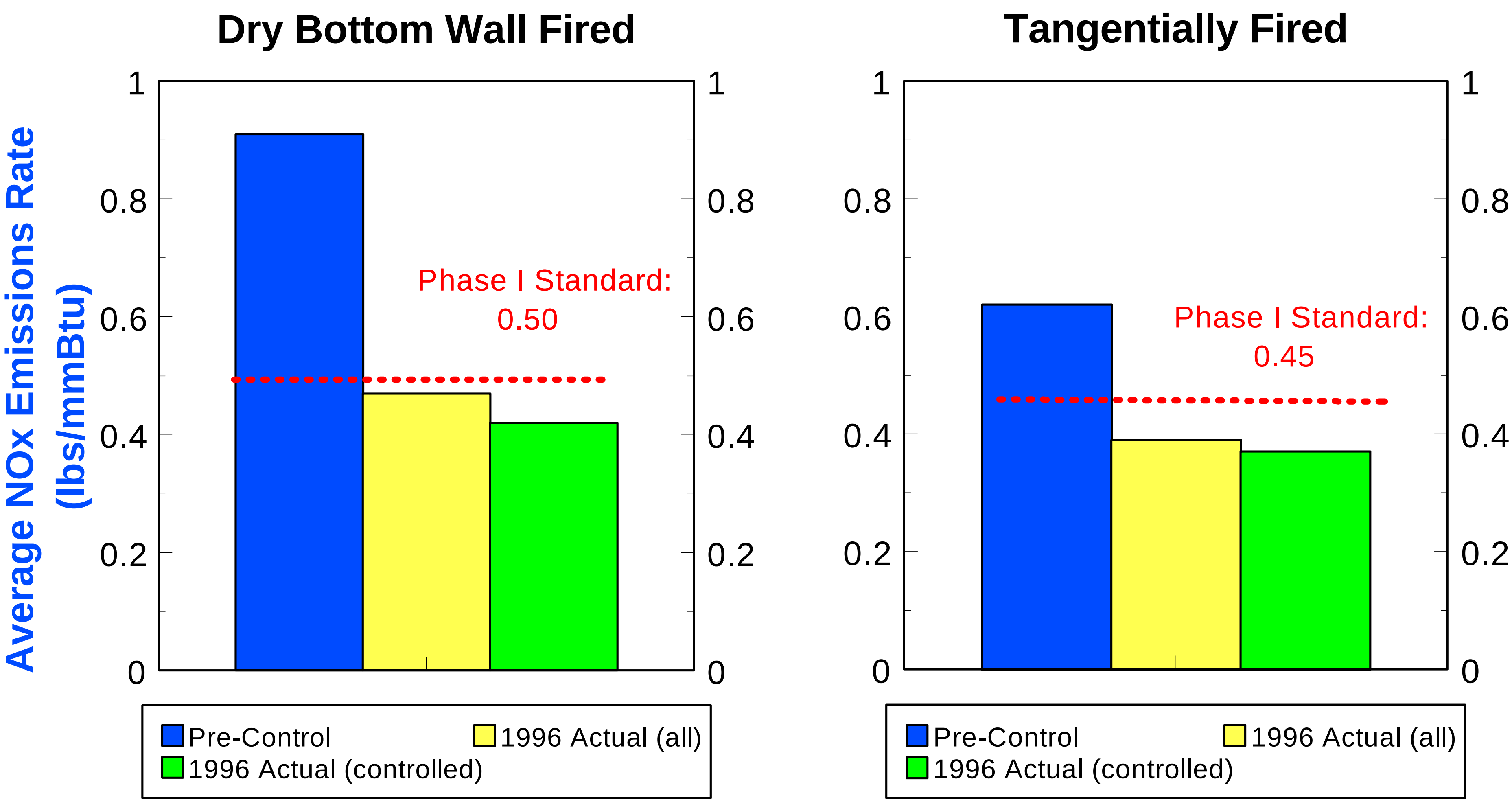
SO2 ALLOWANCE PROGRAM: COSTS

- In 1990, estimated to cost $4 billion per year by 2010
- By 1994, estimated cost dropped to $2 billion per year by 2010
- Less than half the cost of command and control: $5 billion per year
- 1 percent of government air pollution control personnel for 40 percent of emissions reductions under 1990 Clean Air Act

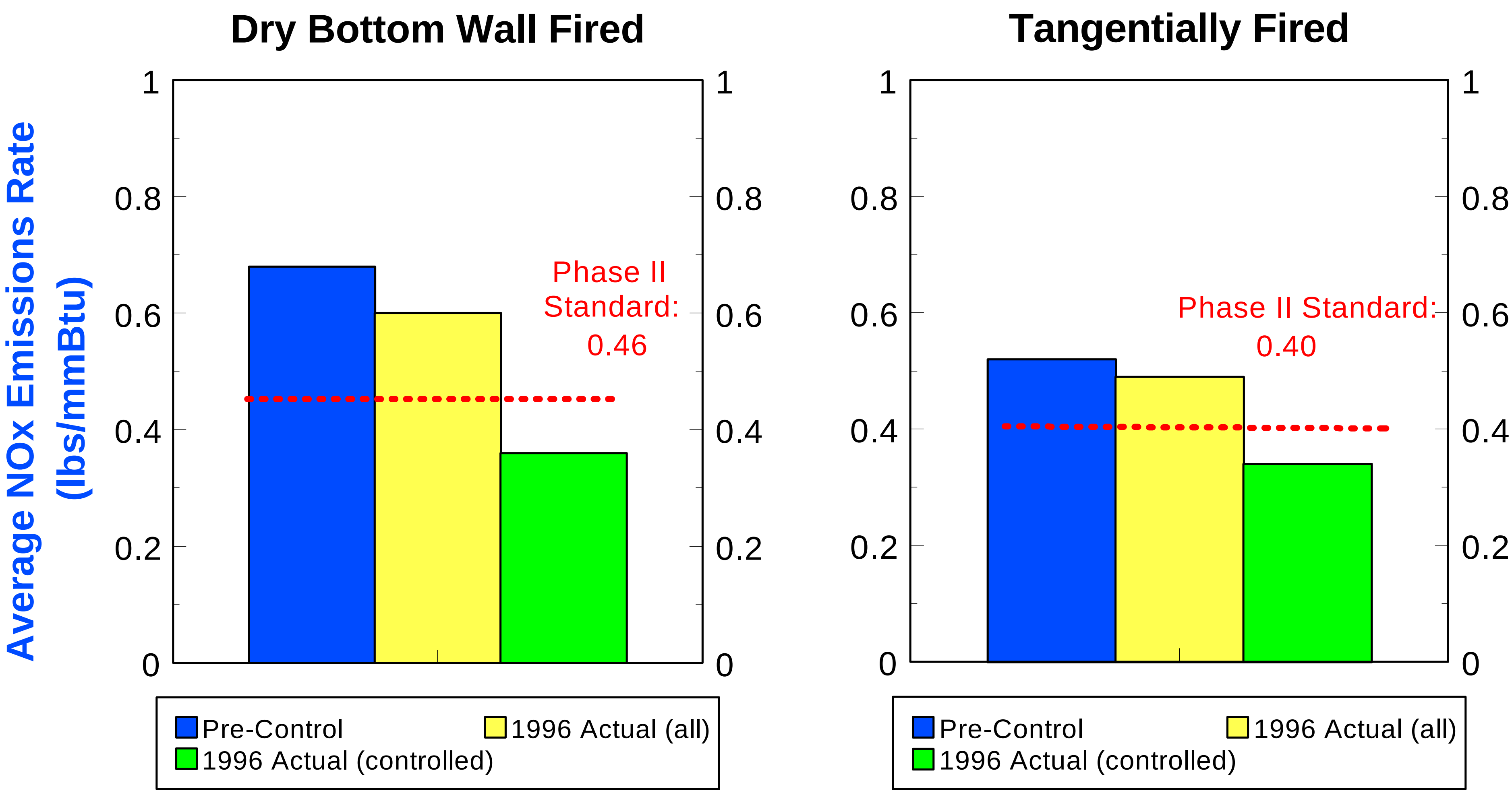
UTILITY NOX EMISSIONS
(1/3 of total U.S. NOx emissions)



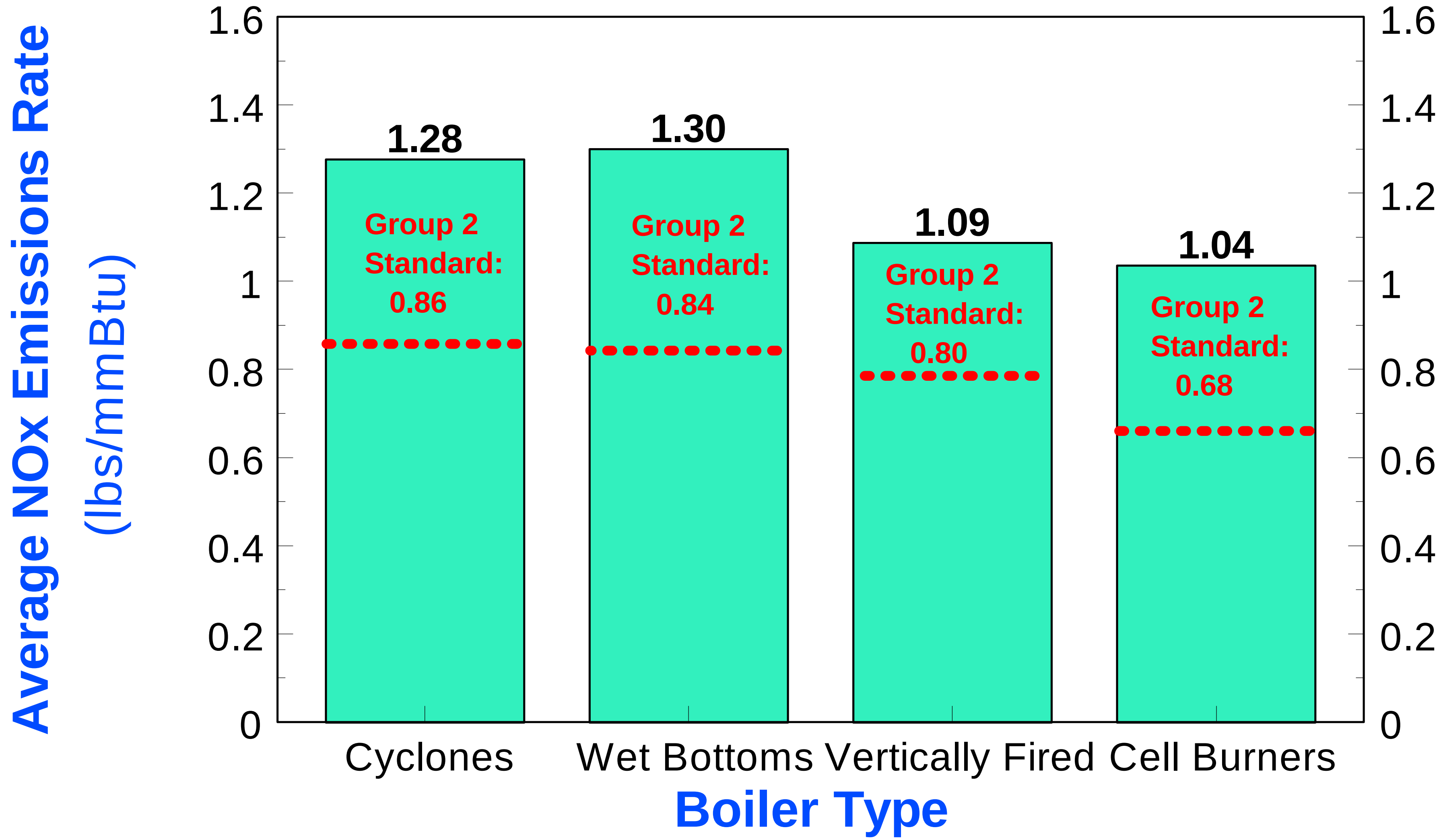
Group 1, Phase I
NOx Emission Rates



Group 1, Phase II NOx Emission Rates



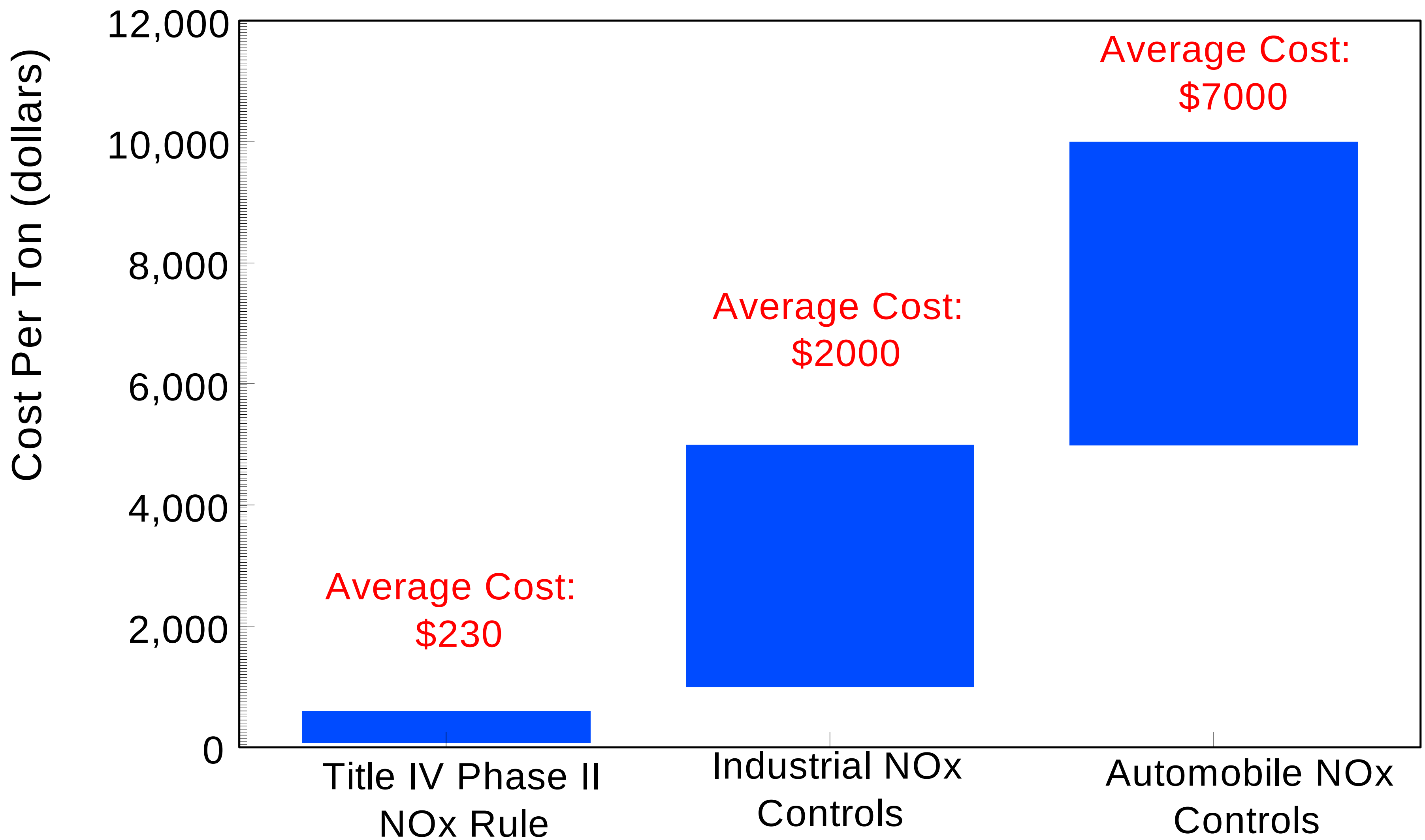
GROUP 2 BOILERS
NOx EMISSION RATES



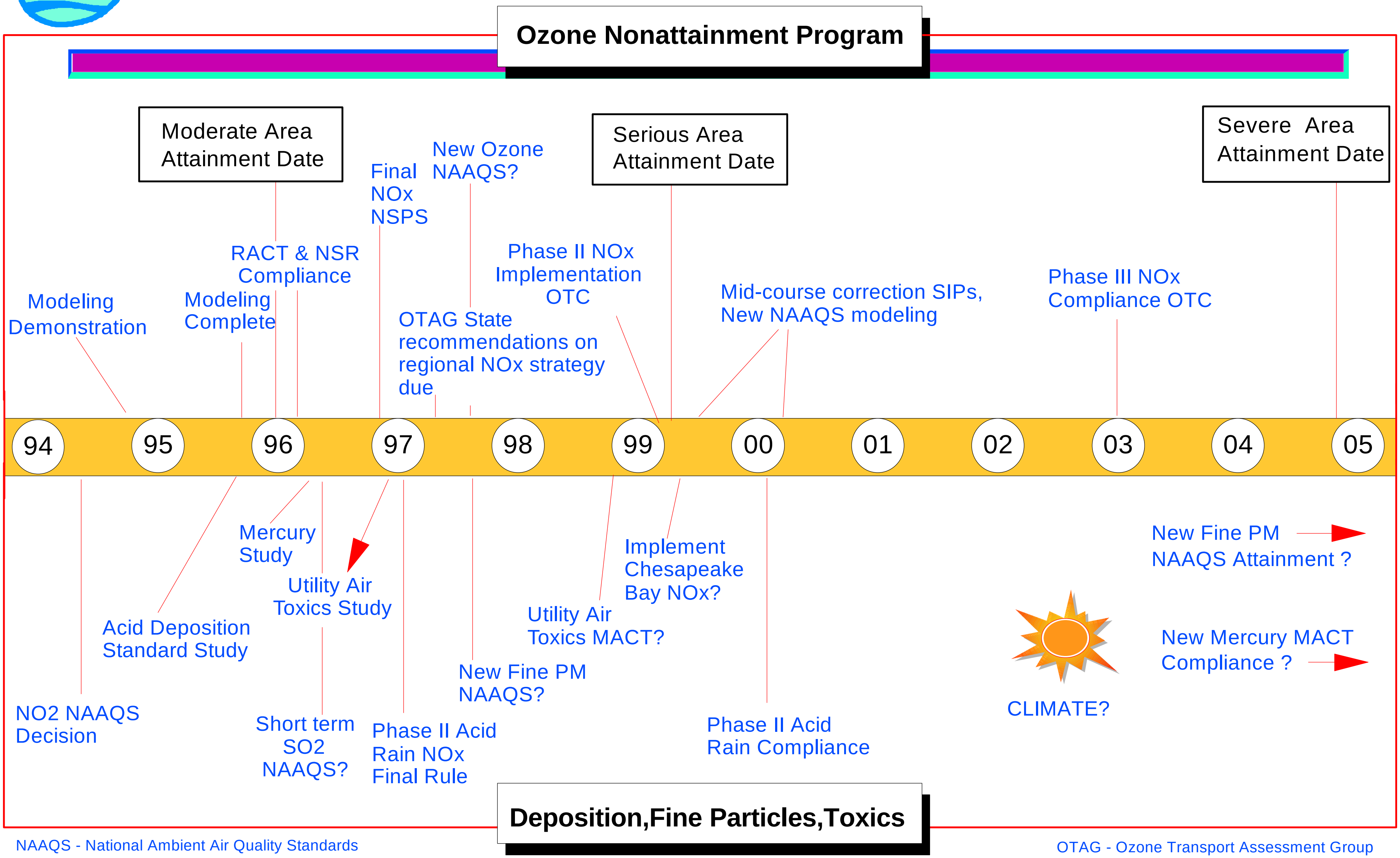
NOx COMPLIANCE OPTIONS

- Boiler-by- boiler compliance with annual emission limitation
- Emissions averaging across holding or operating company
- Alternative Emission Limitations (AEL) for boilers unable to meet limits with Low NOx Burners (LNB's) or Group 2 Technology
- Early Election option for Phase II, Group 1 boilers
- Cap & Trade option for Phase II boilers

COST EFFECTIVENESS OF NOx CONTROL (by Source Category)



Electric Power Regulations Timeline - Clean Air Act



NAAQS - National Ambient Air Quality Standards
NSR - New Source Review
NSPS - New Source Performance Standards
OTC - Ozone Transport Commission

OTAG - Ozone Transport Assessment Group
SIP - State Implementation Plan
MACT - Maximum Available Control Technology

CLEAN AIR POWER INITIATIVE

Goal: To develop an integrated strategy for achieving the goals of the Clean Air Act with respect to the power generating industry

WHAT WOULD A NEW APPROACH LOOK LIKE?

- Translate health & environmental goals into emission targets
- Employ cap & trade with banking
- Provide more certainty, flexibility, & cost savings
- Reduce continuous and disjointed regulatory hits

SCENARIOS ANALYZED

- Traditional Regulatory Approach
- Nationwide caps on NOx, SOx, (and possibly mercury), with trading & banking

NOx CAP & TRADE SCENARIOS ANALYZED

Year 2000

Set allowance caps based on Title IV NOx rule

Summer = 2.2 million tons

Winter = 2.9 million tons

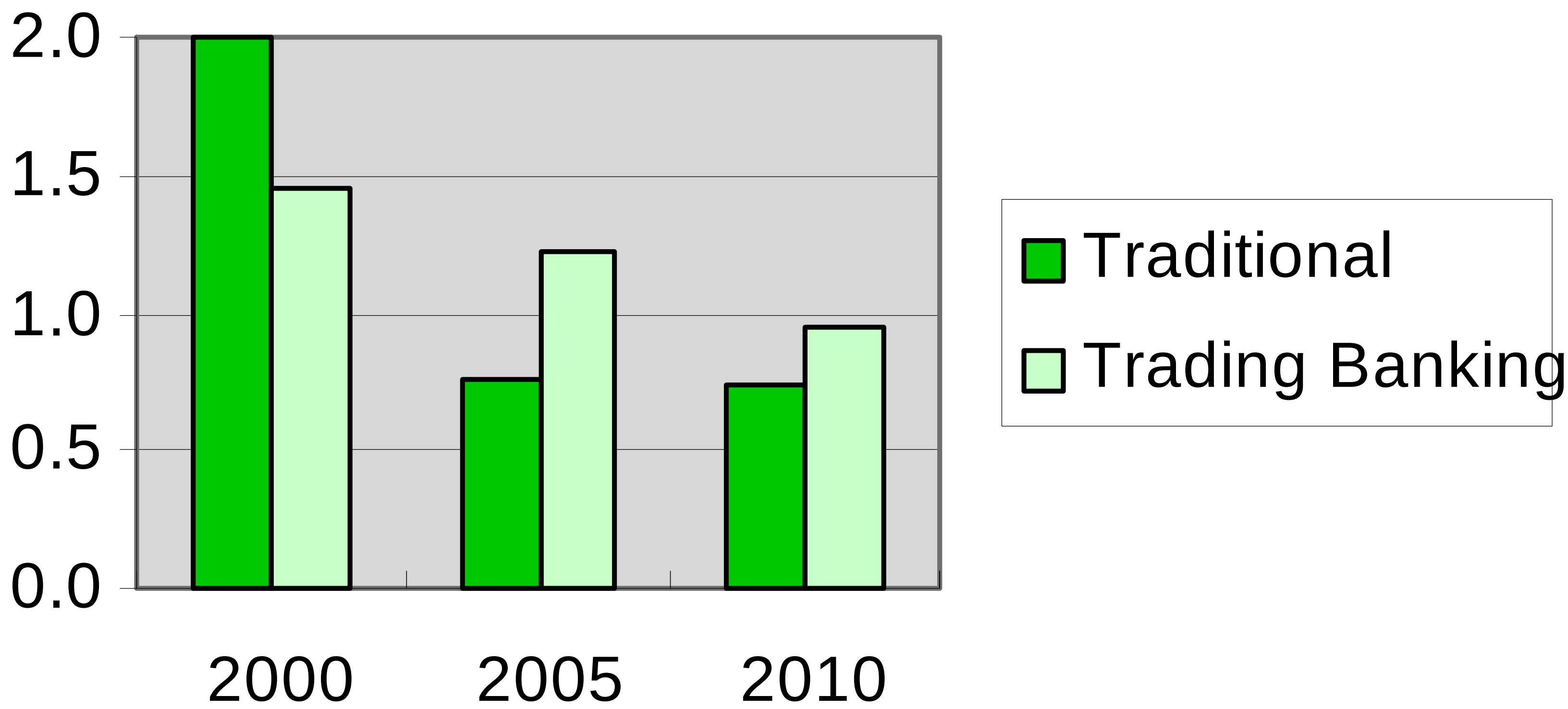
Year 2005 (3 Scenarios)

Lowered summer allowance cap to 1.3 million tons, 1.0 million tons, and 0.8 million tons (bas on 0.25, 0.20, & 0.15 lbs/mmBtu rates)

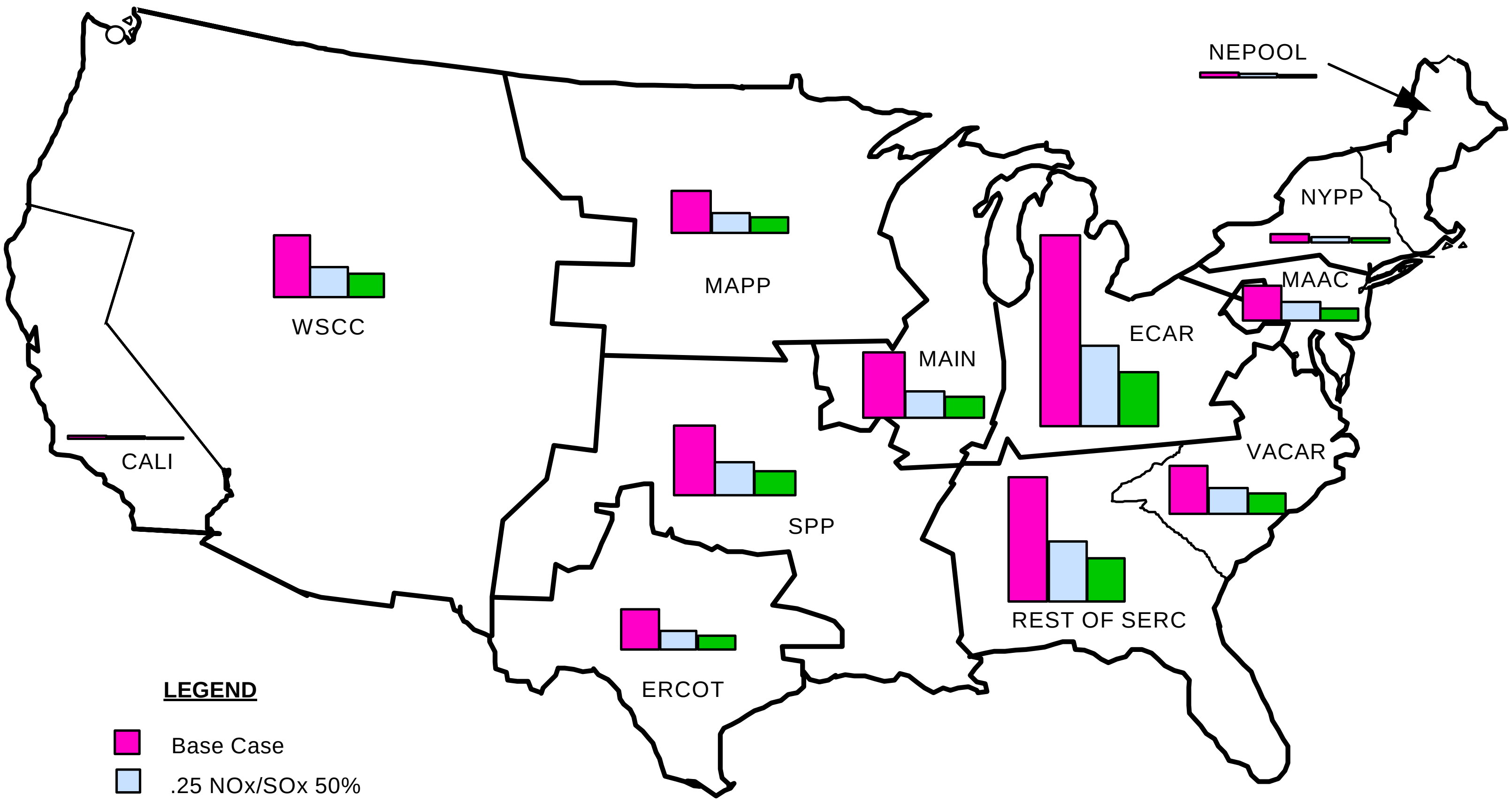
SO2 CAP & TRADE SCENARIOS ANALYZED

- Lowered Title IV allowance allocations by 50 percent in 2010
- Lowered Title IV allowance allocations by 60 percent in 2010
- Lowered Title IV allowance allocations by 50 percent in 2005

Summer NOx Emissions of the Traditional and 0.15 NOx/SOx 50% Trading/Banking Options (million tons)



Comparison of Summer NOx Levels in 2010 for the 0.15 and 0.25 Options

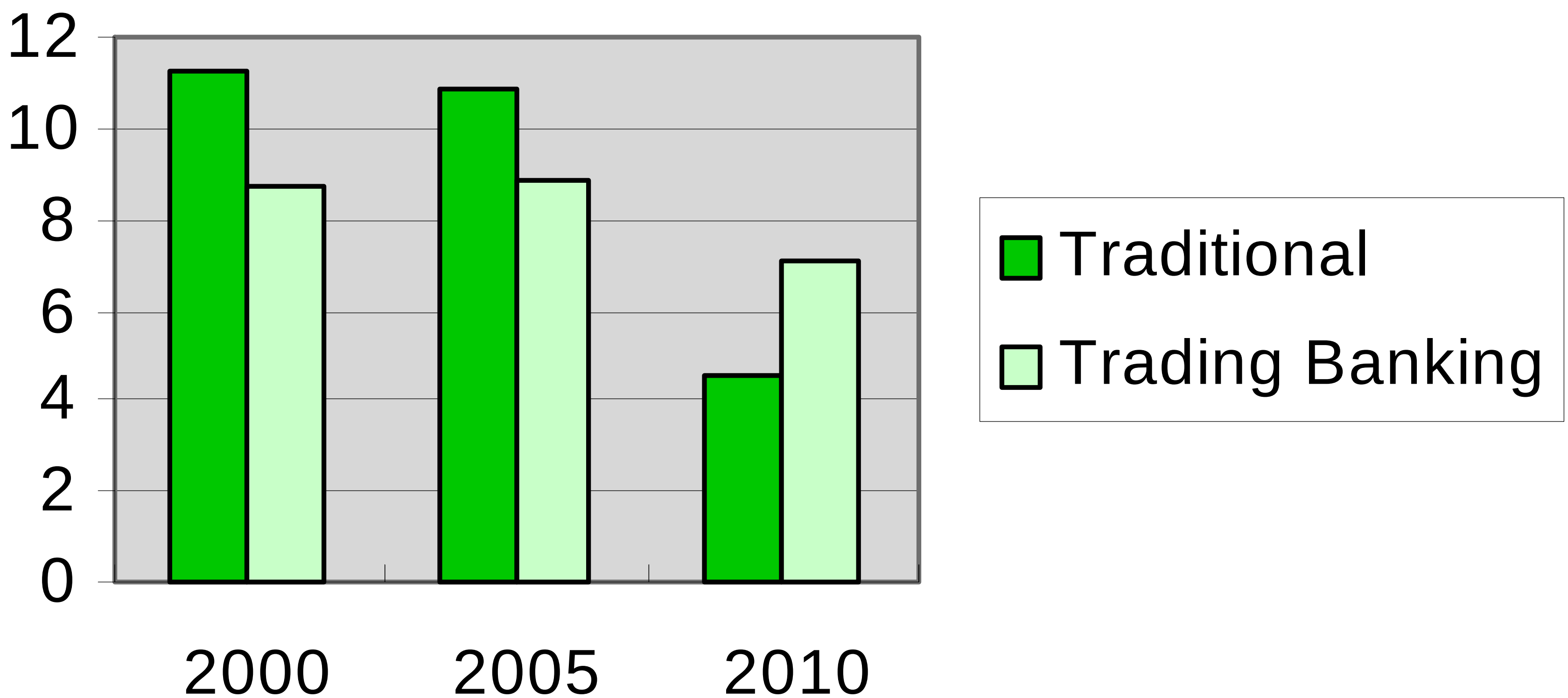


LEGEND

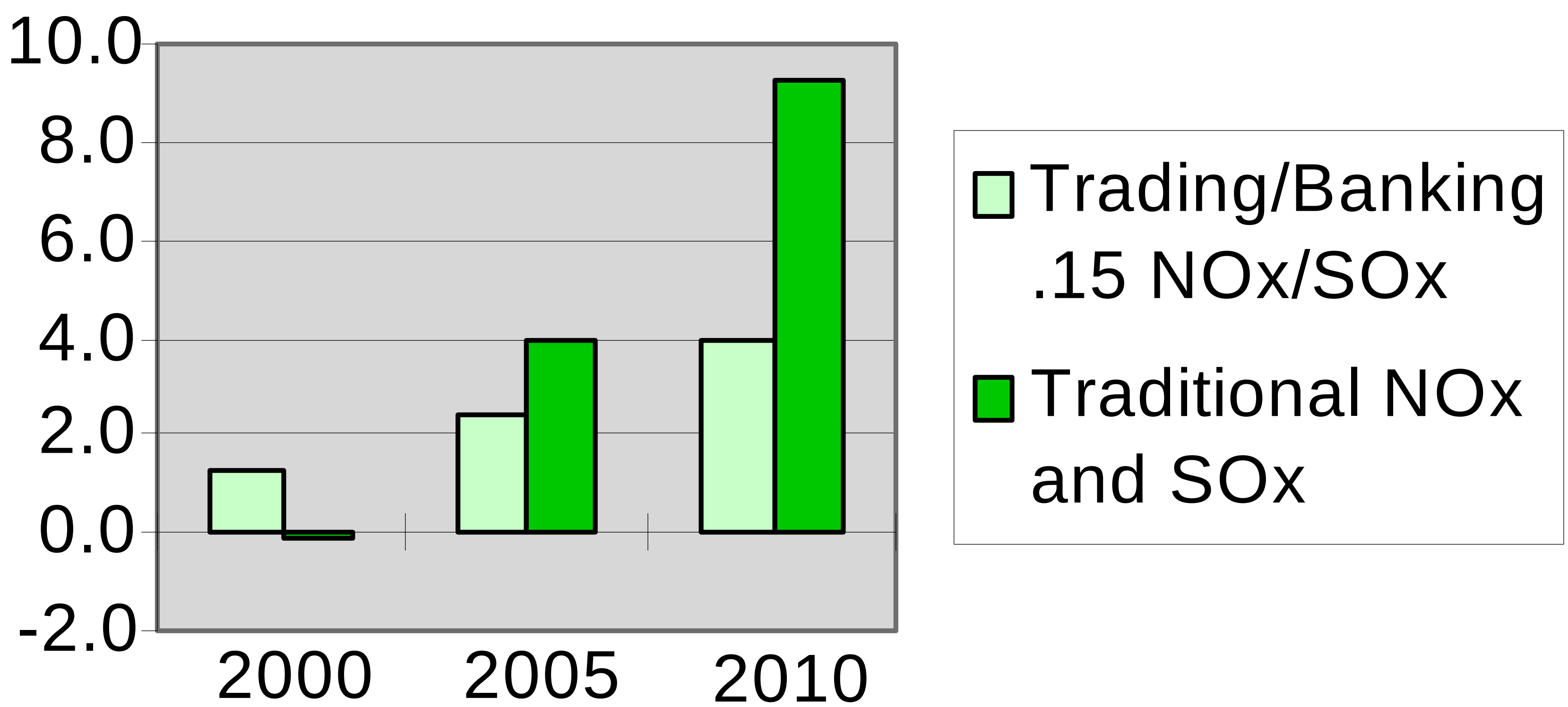
Base Case
.25 NOx/SOx 50%
.15 NOx/SOx 50%

SCALE: ECAR Base Case = 775 ,000 tons

SOx Emissions of the Traditional and 0.15 NOx/SOx 50% Options (million tons)



Costs of Traditional vs Trading/Banking Approach to NOx and SOx ($Billions)



For More Information on The Acid Rain Program or CAPI

Visit our Acid Rain Home Page:

http://www.epa.gov/acidrain/ardhome.html

Visit our CAPI Home Page:

http://www.epa.gov/capi

ENVIRONMENTAL ISSUES AFFECTING CCT DEVELOPMENT

Maura Reidy
Legislative Assistant to
Representative Sidney R. Yates (D-IL)
U.S. House of Representatives
Washington, DC

Legislative Issues Relating to CCTs

While no final legislative schedule has been set for the new Congress two issues with strong environmental ramifications which are likely to affect the coal industry seem to top the list of closely watched debates in Washington - the Environmental Protection Agency's proposed new ozone and particulate matter standards and utility restructuring.

EPA's Proposed New Ozone and Particulate Matter Standards

Background

On November 27, 1996, the EPA proposed new encompassing air quality standards for ground-level ozone (smog) and particulate matter (soot), based on evidence of harm to human health and the environment.

Compared to the existing standards, these new standards are much more stringent. The EPA believes these new standards are necessary in order to meet the Clean Air Act's requirement that air pollution not adversely affect public health.

EPA and a board of independent scientists have reviewed 86 particulate matter related health studies, covering millions of people, that showed harmful effects from breathing particles at the current standard. Another 185 of the latest ozone-related studies on human health were also reviewed. All of them showed harmful effects from ozone at the current standard, including 1.5 million incidences a year of significant respiratory problems.

The proposal is based on a thorough review of the best available science and the EPA expects to hear from a wide range of interested parties, from scientists and environmentalists to industry experts, small business owners, doctors and parents, in order to receive the broadest possible public comment and input on this important issue. Stricter limits for urban smog and soot would prevent as many as 20,000 premature deaths each year and relieve the suffering of millions of Americans afflicted with asthma and respiratory diseases.

Public Comment

There will be a 60-day formal comment period for each of the rules being proposed. The purpose of the comment period is to reach out to all stakeholders in order to obtain the best information available for determining the appropriate final standards. There will also be an EPA sponsored public hearing.

Congressional Review of Regulations

Once a final regulation is issued, it will be among the first major environmental rules reviewed by Congress under the new Small Business Regulatory Enforcement and Fairness Act. Under this legislation, enacted in March 1996, federal agencies promulgating major rules must submit to each House of Congress and the Comptroller General a copy of the rule and the cost benefit analysis of it. Before the rule can take effect, Congress is given 60 legislative days to pass a joint resolution of disapproval. A resolution of disapproval would prevent the EPA from implementing the new standards or from issuing them in substantially the same form. Such resolutions are subject to the presidential veto power and it would take a two-thirds majority in each chamber to prevent the implementation of new standards. Basically, Congress gave itself veto power over new regulations. Many stakeholders are opposing the new standards, claiming they are expensive, unnecessary and hurtful to the economy. Already stakeholders are making appeals to Congress to intervene. Aggressive and expensive lobbying efforts are in place.

Other Legislative Options

As the administrative rulemaking process proceeds, Congress can conduct oversight and consider use of the appropriations process to influence the EPA. The FY97 appropriations conference report for the EPA contained language expressing the committees misgivings concerning new particulate matter standards even before the EPA proposal was released. Congress could also revisit the Clean Air Act and enact amendments to it that target the ozone and particulate matter standards. That process would occur in the authorizing committees - Senate Committee on Environment and Public Works and House Committee on Commerce.

EPA has reached out to Congress to get their views on the proposed rule. Briefings have already been held on Capitol Hill with staff and it is expected that the EPA will continue to be forthcoming during this process. All comments by stakeholders will be addressed and since this is a very complex process it could take some time. It remains to be seen whether or not the entire matter can be resolved during the 105th Congress, particularly in light of the symbolic legislative changes pertaining to promulgating federal rules.

Utility Restructuring

The House Commerce Committee and the Senate Energy and Natural Resources Committee are both involved in another intense debate in Washington - Utility Restructuring. At issue is the right of every consumer to choose their own provider of electric power. Some people contend that competition in the electric power industry is coming, just as it has for the telecommunications industry.

The House and the Senate have both been working on legislation that gives consumers choice of electric service. The Clinton administration began holding hearings around the country on competition and is currently drafting legislation. Many states have already announced plans to implement some degree of consumer choice.

Democrats strongly believe we should develop our energy resources in ways that will not cause harm to the environment, the consumer or the taxpayer. Conservation is a critical element of our energy policy.

According to the Senator Dale Bumpers of Arkansas the ranking member of the Energy and Natural Resources Committee, “Properly handled, greater competition in the electricity industry should lead to greater customer choice and lower electricity prices -- just as competition has in the long-distance telephone business. Improperly handled, it could lead to higher prices for some customers and the loss of some customer services.”

The bottom line is that any legislation Congress passes must benefit the public as a whole and not just the utility companies and their largest industrial customers.

Barbara Wainman
Assistant to the Chairman
Interior Appropriations Subcommittee
U.S. House of Representatives

Fifth Annual Clean Coal Technology Conference
Tampa, Florida
January 7-10, 1997

Whenever I talk about energy I'm always reminded--I've been on the Hill, you know since 1981--some of you have been working on these issues since the 70's--but 1981 to have been on the Hill is a very long time. I'm very old up there if you've ever walked around most people look like they're about twelve--like Maura.

Anyway long enough to have been around during the last speaker that had crises. Jim Wright used to tell a story about energy and how one of his constituents came up to him one time and was talking to him and he says "Jim, I'm really worried about energy, we really have to worry about it." He says, "You know we can't keep burning coal, coal is dirty. It's not a good thing to keep burning coal. We can't keep using oil, because oil is in the unstable Mid-East and he said I'm worried about that. He says we can't keep sending our troops over to fight to protect oil. He says nuclear's just not safe, we can't use nuclear. So the speaker said well Joe, what do you think is the answer. He says we just have to use more electricity."

Well that would be funny, if it wasn't pretty reflective of what a lot of people know about our energy policy. A lot of those people that have a very low level of knowledge about energy and the issues that all of us in this room care about, are some of our Congressman and their staff and it's not that their not interested or anything but Congress really tends to be crises oriented and there is no energy crisis. There hasn't been in recent memory. So it's not something that's really on the Congressional radar screen. And if you look at this Congress, speaking about staff being younger, I start looking every year to see how many members are younger than I am. And this is a very young Congress. Young in terms of experience and a lot of them young in terms of age, and there's a many people up there. I remember the energy crises of the early 70's, because I had just gotten my drivers license and I got to always take the family vehicles on the odd days when the license plates worked and filled them up. And some of these guys weren't even driving, they don't even have that exposure.

So we really have a job to do in terms of trying to focus on how do we deal with the energy issue, absent a crisis. Congress is looking at budget crises and Medicare crises and those kinds of things, and their philosophy is "if it ain't to broke then don't worry about it." So we have to think of how we are going to deal with the Congress in those views.

I think that to some degree what it means is the way we're going to deal with energy policy is going to be incremental. I don't think we're going to see big sweeping energy policy acts or even utility deregulation in the next two years. I think it's going to be an incremental process.

Now what does that mean for all of us. I think it means that what every one of us in this room, I'm mean you all need to be doing, and those of us like Maura and I who are more familiar with these issues, need to be helping you doing is "Education." I think it's very important that you get out and start talking to your Congressman and your Senators and their staff about what issues are important to you. Talk to them in ways that they can understand that "I'm pretty familiar with this."

I've learned a today, but there's a lot that I hadn't a clue what was talked about, so I think you need to get out there and talk about these issues so that those of us who don't spend our whole lives working on this, which is most of the Congress, can really understand and understand why it's going to be important to them. Why it's going to affect their district. Tom and I were talking at lunch, about, if you throw half of this country into non-attainment, you're going to have a real impact. But most members don't know that, they don't know what non-attainment is and so you need to be starting now. Get out and really start the education process because we're going to be dealing with these issues. Not next week, not next month but over the next period of years and it's very important to not go and say here's what I want you to do for me, but here's what I want to tell you about this issue, I think that's very important.

What does all this have to do with the impacts for clean coal technologies. I really find that I agree very much with what Linda said earlier. When we established the clean coal project, I was around at the birth of the clean coal program so I'm very interested in how it finishes up. But I remember what I call the "3 E's." The program was founded because it was going to make these technologies more *economical*, it was going to make them more *efficient*, it we were going to make them more *environmentally* friendly. I think right now the issues, two of those things are being very effected economics and the environment are the issues that the projects are going to be most effected by where these two issues of utility restructuring and changes in the whole Clean Air Act. But I don't think that necessarily has to be negative. I think that we should not look at these changes as "stumbling blocks" but as "stepping stones", and how can we use these to make the clean coal program the true success that it can be. I think it is very important that all of you continue very aggressively to work on deployment, to have the most options to respond to what ever Congress comes up with. You can't sit in this room and know what Congress is going to do. I think these issues, like you said, are going to be necessarily dealt with in the 105th Congress, maybe the 106th or 107th and we don't have a clue of what those are going to look like.

A classic example of where an industry failed to do that is one that we're dealing with in another area of DOE. When some groups are Republic Congress, they thought "heck" now we can go in and not worry about getting our refrigerators more efficient. I'm glad to here refrigerators are really efficient, because that helps the company that I'm interested in, but DOE thinks they need to be more efficient. So a lot of the industry just sort of sat back thinking the Republican Congress is going to save us from having to make these refrigerators more efficient, and they're not necessarily. So you don't want to sit back trying to figure, okay here's the lay-of-the land, because the lay-of-the-land can change every two years. So I think it's important to get out there and keep working on getting these technologies into the market, get them sold, get them demonstrated and be very aggressive on that front. Because we don't know what Congress is going to do. We can't predict from day-to-day. But I think we need to look at these issues as positive opportunities and to be working to have the most options available for the coal industry to make sure that coal continues to play the important role in our economy and environment that we all know it can.

Thank you very much.

A Utility Perspective on the Deployment of CCTs Into the Next Millennium

Michael J. Mudd
Principal Engineer
AEP Energy Services

ABSTRACT

The successful Clean Coal Technology projects which are being discussed in this conference are all a testament to the positive advancements that can be made with environmentally superior technologies when the government and industry cooperate in the context of a properly funded and a well thought-out program. Many of the technologies developed in the Clean Coal Technology Program have taken a competitive position in the marketplace, and many others are on the verge of being competitive in the marketplace. Based on the success of the Clean Coal Technology Program, one would expect that they would be ready for full deployment in the marketplace as we approach the next millennium.

This is not happening. There are several hurdles that impede their deployment. Some of those hurdles, such as the higher first-of-a-kind cost and technology risk factors that accompany not-yet mature technologies, have existed since the initiation of the Clean Coal Technology Program. However, several new hurdles are impeding the market penetration of Clean Coal Technologies.

Those hurdles include the radically different marketplace due to the restructuring of the electric utility industry, a soft market, the difficulty in financing new power plants, low natural gas prices, and lower-cost and higher-efficiency natural gas combined cycle technology.

I. INDUSTRY RESTRUCTURING

The restructuring of the electric utility industry is being reviewed in detail at other sessions. Therefore, I will not discuss that aspect in detail here. However, at the same time, it is important to acknowledge that the restructuring of the industry from cost-based prices to market-based prices will have a great impact on the commercialization of CCTs in the domestic electric utility industry. This is because the pending change in the electric utility industry has resulted in the deferral of construction of new plants in the United States into the next decade or beyond. Until the rules of the newly restructured marketplace are known, electric utilities are not likely to add new base-load coal-fired capacity.

II. MARKET FOR NEW PLANTS

The market for new base-load, coal-fired plants in the United States is stagnant. Sales of coal-fired plants are few and far between. The load growth of electricity is lower than was projected twenty years ago when the electric utility industry was adding significant capacity to the grid. As a result, there is ample base-load capacity to serve our nation's electric system in most areas of the United States. Currently, the average capacity factor of the 720 GW of generating capacity installed in the United States is 49.6%. Most of the projected load growth for the next 10 to 15 years can be absorbed by increasing the capacity factor of existing power plants, decreasing reserve margins, and by life extension of existing capacity. It will not be met by adding base-load solid-fuel power plants.

III. FINANCING OF NEW PLANTS

In a regulated environment, utilities based decisions to erect new facilities on prudency, life cycle costs, and the regulatory compact, whereby utilities were allowed to recover the cost of prudent investments provided the facilities were used and useful, and a reliable source of electricity was provided to the ratepayers. In the deregulated environment, the key to building a new power plant is financing. One of the keys to financing is to obtain a Power Purchase Agreement. A Power Purchase Agreement is dependent on the ability of the generator to provide reliable power at competitive prices. The utility, (or GENCO or IPP or any producer of electricity by any other name) would seek a Transmission Company, Distribution Company, customer, or power broker to sign an enforceable long-term contract for the electricity produced by the new facility.

Absent a Power Purchase Agreement, the plant would be a "merchant" facility (eg. the plant is built without any assured purchaser of the power) which entails considerable financial risk. Usually, it is difficult, if not impossible to finance such a facility with project financing (using lower-cost debt to finance the project). A merchant plant would likely be financed with mostly equity (which typically is more expensive than debt).

Let's look at whether or not a Clean Coal Technology Plant could provide competitive power in today's market. Most studies which project the market price for power in the 2000 to 2005 time frame point to an average market price for energy in the range of 20 to 25 mil/kWh, and 30 to 35 mil/kWh when capacity is included in the cost. With natural gas at less than $2.00/million BTU, a Natural Gas Combined Cycle Plant can be competitive with that price level. Most new solid-fuel plants, whether a conventional or a Clean Coal Technology Plant, cannot provide power at that price. The reasons for that follow.

IV. NATURAL GAS

Since 1988, approximately 75% of new generation has been gas fired. The dominance of natural gas in recent years can be attributed to economics associated with the price differential between natural gas and coal, the efficiency of natural gas combined cycle plants, and the decreasing capital cost of combustion turbines.

Natural gas has historically commanded a price-premium factor of 2.5 to 3 (on a BTU basis) over coal. That premium reached a low of 1.25 within the past five years, and has remained well under 2 over the past several years. It is because of this historical price premium that coal-based technologies have been competitive with natural gas technologies despite their higher capital cost. With the lower price premium, coal-based technologies tend to lose out in an economic comparison. Will natural gas prices increase in the future relative to coal prices? Current conditions do not indicate such a trend. Known natural gas supplies have increased by 30% over the last decade. The abundance of reserves, coupled with advances in extraction technologies and competition in the natural gas industry, have reduced natural gas prices by 15% in real dollars in the past five years.

At the same time, the efficiency of gas turbines has been steadily increasing. The efficiencies of the latest fleet of high-temperature gas turbines is approaching 40% for a simple-cycle configuration, and 50% for a combined-cycle configuration. The DOE projects efficiencies of 60% in advanced turbine systems by the next millennium.

Finally, the capital cost of gas turbine combined cycle plants has declined dramatically. The current cost of a Combustion Turbine Combined Cycle Plant (on a $/kW basis) is about one-half the price of a pulverized coal-fired plant.

The combination of lower fuel prices, higher efficiency and lower capital cost has resulted in lower projected life-cycle costs for NGCC Plants compared to coal-fired plants -- both conventional designs and Clean Coal Technology designs.

There are many other issues which impact the evaluation of whether or not a utility should build new generation, and what type of generation should be used. Some of them include environmental considerations, location of plant relative to the availability and cost of fuel, system stability requirements, system needs (peaking, intermediate, or base load) to name a few. There will be selected niche markets where a coal-fired plant is the economic choice. However, in the short term, I believe that natural gas will dominate new plant construction.

V. CLEAN COAL TECHNOLOGIES

Where does this leave CCTs in relation to the domestic electric utility industry? I do not believe that there will be a viable wide-scale market for solid-fuel, base-load power plants -- whether clean coal or conventional in the United States until the need for base-load power reenters the marketplace, and coal can reestablish its competitiveness compared to natural gas.

At the same time, CCTs continue to be good technologies. They have cost advantages, efficiency advantages, and environmental advantages compared to conventional technologies which must not be sold short. They have the potential to provide the higher efficiency and lower capital cost to bring coal back to the forefront for new electric generation. But before CCTs can be competitive with natural gas, they must complete their path along technical and cost maturation curves.

In the long run, coal-based generation must continue to be a viable and important part of our nation's future generating needs. Coal is a natural resource which must not be ignored. Coal is an important aspect of our country's energy security. I believe that the dominant market for new generation in the foreseeable future will be in smaller-size generating stations. Fluidized-bed combustion boilers, especially CFBs, can continue to serve this important market niche, especially where low-grade fuels and alternate fuels (such as pet coke and biomass) are economically available. At the same time, this smaller-size market is where the competition between coal and natural gas will be the greatest. Both PFBC and IGCC technologies could be the "swing" choices for new generating facilities, which could allow coal to capture a large share of the intermediate-size power generating stations in the future.

If PFBC and IGCC can continue down their paths of commercial demonstration and cost reduction, these technologies should offer the opportunity to use coal in medium-size facilities which might otherwise be fired with natural gas. The challenge remains to continue the development of these important technologies despite the fact that the near-term market for new generation, especially coal-fired, is bleak. This is why, absent opportunities in the domestic market, it is so important to continue to focus on developing these technologies overseas.

VI. INCENTIVES

The Clean Coal Technology Program has been the model of the type of incentives that were required in the mid 1980's to assist in the commercialization of CCTs. I believe that the incentives should remain in effect to allow those projects to be completed. At the same time, it is important to acknowledge the context in which the CCT program was initiated. Natural gas prices were declining relative to coal prices, however it was expected by many analysts that would be a short-term situation. The Clean Air Act Amendments were being discussed, but were not yet enacted. Deregulation was being talked about, but it was far from a reality. The cost-sharing provided by the federal government was often tied to enhancing the cost-recovery of the project by the utility through rate consideration.

As previously discussed, conditions are significantly different now. At the same time, incentives are still required to assist the completion of the commercialization of Clean Coal Technologies. Proper incentives are still required to ensure that not-yet-mature CCTs are commercially deployed as opportunities become available. Those incentives must make these not-yet-mature CCTs cost indifferent to the customers. If the only market for CCTs is overseas, and if incentives are required to ensure that Clean Coal Technologies can be proven in this market, then it is better to pursue an international cost-sharing program than to simply claim that we should not spend CCT funds on overseas projects, and lose the momentum gained through the CCT Program.

VII. CONCLUSION

Our nation has invested a lot of effort and money in the development of Clean Coal Technologies -- in excess of $7.5 billion. Electric utilities have played a major role in that development, having been involved in a significant percentage of the Clean Coal Technology projects. This is a testimony to the importance that electric utilities place in the development of Clean Coal Technologies. Our industry and our customers cannot overlook the environmental, efficiency and economic benefits of Clean Coal Technologies. Industry and government must continue to work together to ensure that Clean Coal Technologies are ready to be used in the next fleet of power plants by being an economic choice compared to other alternatives in the future.

A CHICKEN IN EVERY POT
A NEW BOILER IN EVERY POWERPLANT
A NEW POWERPLANT AT EVERY INDUSTRIAL SITE

Robert D. Bessette
President
Council of Industrial Boiler Owners (CIBO)

Fifth Annual Clean Coal Technology Conference
Tampa, Florida
January 7-10, 1997

For those of you who do not know, the Council of Industrial Boiler Owners (CIBO) is a broad-based association of industrial boiler owners, architect-engineers, related equipment manufacturers, and university affiliates consisting of over 100 members representing 20 major industrial sectors. CIBO members have facilities located in every region and state of the country. We have a representative distribution of almost every type boiler and fuel combination currently in operation. CIBO was formed in 1978 to promote the exchange of information within industry and between industry and government relating to energy and environmental equipment, technology, operations, policies, laws and regulations affecting industrial boilers. Since its formation, CIBO has taken an active interest in the development of technically sound, reasonable, cost-effective energy and environmental regulations for industrial boilers. One of our prime objectives is to support and promote the industrial energy base of our country, a foundation of global competitive power.

What you do and are talking about at this conference is directly in line with our objective to promote the industrial energy base of our country. In that context, I want to begin with a quote from Jesse Jackson's remarks to the Democratic National Convention in Chicago:

"What is our vision tonight? Just look around.

This publicly financed United Center is a new Chicago Mountaintop. To the South, Comiskey Park, another mountain. To the West, Cook County Jail, with its 11,000 mostly youthful inmates.

Between these three mountains lies a canyon.

Once Campbell's Soup was in this canyon. Sears was there, and Zenith, Sunbeam, the Stockyards. There were jobs and industry where now there is a canyon of welfare and despair.

This canyon exists in virtually every city in America."

If we look at where the companies which once thrived in the canyon have gone we may not like the answers we find. When we talk about boilers which support the companies which produced these jobs, they are not being built in this country today. When is the last time you saw a major new manufacturing plant being built or considered for any major city or non-attainment area? They are not. The canyon of welfare and despair will never be revitalized without a rebuilding of American industry. Even Mr. Jackson knew this, as he ended his speech at the convention with the following:

"In the Canyon, we must have a plan to rebuild and redeem our cities, to reinvest in America.

I suggest we have at least as much sense as a honey bee, which knows enough to repollinate her flower.

After World War II, we helped rebuild Germany-- the Marshall Plan. We helped rebuild Japan - the MacArthur Plan.

Now we must rebuild America."

Today I want to share with you my thoughts on a problem which all but prevents us from doing this. This problem has increased the complexity for the individual or business to create its own future. There is a perception, throughout the country, which binds our hands as we look to create a better future for our children -- whether they are in the city or suburb.

What is this perception? "Energy Awareness!" There is "no" energy awareness! We as a people take energy for granted. We forget it takes energy to do anything, to provide any product or service. I challenge you to touch something in this room, or where ever you happen to be, which doesn't have energy connected to it in some way. Even touching takes energy.

As we look to the future, our nation's energy awareness will be the determining factor in how and what we are able to do. I do not know what that will be. Right now we have great "Environmental Awareness." To balance the future, we must have an equally strong "Energy Awareness."   In a sense, it is now backwards. I believe people, in general, feel energy happens (made by God, used by man), and environment is created (made by man, used by God). When you think about it, in reality, the environment happens and energy is made. Everyone agrees we must be environmentally conscious as we build our future. However, without energy there is no future as we think of it today.

If we stop and take a look at where we are today, to say the "times-are-a-changin" may be an understatement. EPA's regulatory activity is at its highest level in recorded history. Utility deregulation and competitive sourcing are opening new alternatives resulting in new complexities (including additional environmental complexities), for our day-to-day operations and long-term development considerations. Corporate re-engineering is changing the face of every industrial company in the United States, if not the world. What we see two years from now will not be anything like what we saw two years ago.

Each industry grows, or changes, as a result of the pressures it experiences. If you are to be successful you have to look at what these pressures are and how to address them.

What are the pressures on the industrial boiler owner today which will affect how he meets his energy needs?

- CHANGES IN OPERATOR KNOWLEDGE AND EXPERIENCE
  Retirements and Loss of Naval Training

- INCREASING ENVIRONMENTAL REGULATIONS AND COMPLEXITY
  NAAQS Integration, ICCR, FERC, OTAG

- INCREASING GLOBAL COMPETITION
  Cost of Goods Sold, Regulation Difference, Profitability

- DEMANDS FOR INCREASED ENERGY EFFICIENCY
  Global Climate, Cogeneration

- DEGRADATION OF FUEL SUPPLY QUALITY AND CONSISTENCY
  Waste Fuels

These pressures have created a new environment in which the industrial power plant must operate. The ability of the industrial company to compete has been seriously complicated. The goods and services which are produced to maintain our standard of living and to provide the social benefits to the people of the United States are becoming more expensive primarily due to the increasing burden of regulations, environmental and others. Talking primarily about environmental regulations, these regulations are generated without significant positive benefit. We forget it takes energy to clean up the environment or do anything.

As a result of these pressures, especially the environmental regulations, we see some major trends which may be indicative of what the future will hold.

- Industrial development is now mostly in other countries and not in the United States.

- There are very few people who know how to burn coal or fuels other than natural gas in an efficient, environmentally acceptable way.

- The question of who should own my powerplant is given serious consideration. As more companies proceed down this path, the financial plant, definition and labor problems will be worked out for others to follow.

- Staff reductions and travel curtailments are commonplace to meet the ever increasing globally competitive pressures and the demand for short term profits by investors and management. Capital for powerplants vs. production.

- Environmental regulations have forced rapid development of technologies without a plant operation infra-structure.

- Regulations emanating from the implementation of the Clean Air Act Amendments of 1990 are being generated on all fronts at the same time without sufficient time to determine the true costs and benefits. However, all affected parties are beginning to talk to each other.

- We are beginning to see a trend where savings are being generated through team efforts. There is a greater acceptance of owner/vendor/engineer groups working together. A new way to work out projects.

- Natural gas is the primary industrial fuel of choice.

The single most important question to come out of our annual meeting in October was: “what is the future of industrial energy needs in a deregulated utility market?” We are going to try to work this out and develop a program to specifically address this issue over the next year.

Today's situation is one of complexity and multiple energy/ environmental issues forcing companies to look at the increasingly complex solutions with increasingly smaller staffs.

I must say, I do not believe there is anyone in this room who does not want a clean and safe environment for our children and our grandchildren. This has become a top priority in everyone's mind. It is like buckling seat belts when you get into a car; where once there was resistance, now there is a natural acceptance.

Where do I think the industrial powerplant will be in the next 10 to 20 years?

- The industrial powerplant may not necessarily be owned or operated by the users of the steam and power. The powerplant will be considered a profit center.

- Powerplants will be built to generate electricity based on a process steam load to capitalize on the system efficiencies. The “steam only” system may become extinct.

- There will be a drive for effective and efficient increased consumption of any waste which can be used as fuel, if not completely banned by the EPA, under a radical combustion strategy and maximum achievable control technology (MACT). Large Wholesale Electric Generation’s (WEG) will be located at mine sites or where there is low cost fuel.

- The next generation of electric powerplants will be smaller (40 to 240 MW) systems located at or near the major industrial energy users, taking advantage of the increased efficiencies of cogeneration.

- Environmental regulations will be generated with real and valued input by all interested parties. These may provide a sense of realism and benefit for the costs incurred. The Industrial Combustion Coordinated Rulemaking (ICCR) and Ozone Transport Assessment Group (OTAG) are examples of this.

- The environment will be cleaner; and people will be better educated. They will not be scared like “Goosy Lucy” listening to “Chicken Little“ when they hear words like endocrine disrupters, ozone hole, alar and radon.

- Clean coal tehnology programs will have a more important place in everyday decision making.

The above projections are based on a sense of optimism that there will be sufficient energy awareness to balance the environmental awareness which exists today. If this happens we will be able to replace our aging industrial energy base and provide the support for an increased national productive capacity. If it does not happen, I am afraid to consider the possibility that we will become a nation of service providers to the world and importers of goods. Of course, this is what some would like to see -- a return to the primitive times.

"In Order to be Successful, Technology Must Adapt to the Changes in the Marketplace"

James C. Houck
General Manager
Alternate Energy Department
Texaco, Inc.

First, let me tell you how proud Texaco is to be a part of the team which contributed to the success of the Polk Power Station IGCC -- the cleanest coal power plant in the world. I also want to commend our friends at Tampa Electric Company for their vision, their energy and their spirit that were critical to bringing this plant on line -- and on schedule. Finally, I want to thank our DOE hosts for organizing this fine conference.

Texaco has been in the gasification business for more than 50 years, and the only "constant" we have seen in the marketplace is change. The marketplace is no longer a set of neat and distinct boxes. It is hard to discern the lines between the utility and non-utility sectors; and between the power and the refining and chemical sectors.

In the same way that marketplace distinctions have evolved, technology distinctions have evolved. In adapting gasification to the marketplace, we have learned not to view gasification as strictly a "power" technology, or as strictly a "coal" technology. It is, however, a "popular" technology because it is so many things to so many people. Thus, the emphasis of my remarks are on "technology that meets marketplace needs," not on "clean," or "coal."

A little perspective on where we've been and what we've learned will help us understand where we're going. Gasification was first used in the late 18th century to "cook" coal to produce gas for street lamps. Over the next hundred years it was primarily used to produce town gas. During the 1920's gasification was first used by the chemical industry to synthesize chemicals. During World War II and for several years thereafter, gasification was used to produce liquid fuels from coal and natural gas.

Texaco entered the gasification market during this time period, and we licensed our first commercial plant in 1946. At the start, the gasification technology appealed to the chemical industry, followed later by the refining industry, where it was used to produce hydrogen from oil and natural gas.

With the energy crises of the 1970s, America decided to become energy self-sufficient and since our most abundant energy resource was coal, it was clear that coal-based, energy self-sufficiency had to be balanced with environmental concerns. Hence, the creation of the Synfuels Corporation and later the Clean Coal Technology Program. As has been thoroughly documented at prior CCT conferences, it is important to note that these programs did indeed contribute to advancement of technology, including commercialization of technology, in the power sector. (And Texaco is proud to have played an important role in the Clean Coal Technology Program.) It is equally important to note that some of these technologies have been, and continue to be, adapted from other, more traditional, marketplace applications.

The lessons we learned from history is that the gasification of 1996 is a far cry from the gasification of 1796. In fact, the only point of commonality is the name itself.

The marketplace, both here and abroad, has changed dramatically since the Clean Coal Technology Program was first legislated. In the United States, the Electricity Market is undergoing the most profound change since Edison first invented the light bulb. Overseas, the electricity markets are growing at a much more rapid pace than total energy demand.

We believe gasification can play a key role in the marketplace competition for power generation. National privatization and regional imbalances in projected supply/demand scenarios have created opportunities where gasification has successfully competed. Markets where the demand for power is combined with the lack of inexpensive, indigenous fuel (for example in India, Taiwan and Japan), or where the ability to use a variety of low value and/or waste feedstocks in combination with coal feedstocks, have also created opportunities where gasification has successfully competed. An interesting result from our successful efforts in the area of low value and waste feedstocks has been the importance of not necessarily characterizing gasification as a "clean coal" technology. Rather, it is a "clean, versatile" technology, with an emphasis on both "versatile" and "clean."

Against the backdrop of the recent gasification successes in the marketplace, it is important to ask "What are the challenges to future commercial success?" Let me share our thinking on a few:

1. Government -- The old attitude was that regulations must become more strict in order to foster an environmental in which gasification can succeed. The new attitude should be that government should step aside and let the market figure out how best to make this technology succeed. And that is by recognizing that a technology is only as versatile and flexible as the laws which regulate it. Gasification can do many things, and solve many problems, but only if the lawmakers are willing to advance their regulations as quickly as industry advances the technology. The EPA and other countries' environmental agencies should recognize this, as should the World Bank.

2. Perceptions -- Most of the technologies showcased at this conference are fully commercial. Gasification certainly is. So let's stop referring to these projects as "demonstration," let's stop talking about these efforts as R&D, and let's stop suggesting that these technologies need special incentives to deploy them. Similarly, let's recognize that as commercial technology, it has met the marketplace requirements for reliability and availability. Too often, as we develop technology for new marketplace applications, we are tempted to emphasize the "learning curve" issues and not give credit when those issues have been clearly addresed.

Gasification is Commercial. The commercial lending community recognizes this, as evidenced by the successful projecting financing of two IGCC projects in Italy. And the Utility market recognizes this, as evidenced by the winning bid put forth by GSK in Tokyo Electric's IPP solicitation.

3. Cost - Although gasification has enjoyed recent commercial successes, the major factors contributing to the overall costs of projects still need improvement. In particular, installed capital cost of a gasification facility continues to be perceived as a barrier to widespread commercial acceptance. The techniques for capturing and implementing reduction in cycle time, along with improvements and standardization in engineering designs are known and being used to make improvements. With the continued efforts of many of the world class technology suppliers and engineering/construction companies represented here today, we are confident this barrier will be eliminated. Overall costs can also be reduced through multiple product facilities where incremental capacity additions to accomodate more than one product result in economies of scale.

What will be the model gasification plant in the next millennium? That's tough to predict, but our current successes would illustrate the folowing trends:

1. Multiple feeds -- The feedstock versatility of gasification mentioned earlier will be more and more common. The kinds of materials we wouldn't have imagined just 20 years ago (for example petroleum coke; municipal wastes and sludges; industrial and hazardous wastes; biomass) are frequently included in project considerations. The Texaco gasification projects at the STAR Delaware City refinery in Delaware, the Texaco El Dorado refinery in Kansas, the Ube Ammonia facility in Japan, and the Quantum Chemicals facility in Texas are examples of this.

2. Multiple products -- As the walls that used to neatly define industries come down, single facilities making multiple products will become more common. With gasification's primary output being syngas, the potential for achieving greater project economies by producing fuel, hydrogen, chemicals, steam and power from syngas is significant. Texaco gasification has long been operating in the multiple hydrogen/chemicals environment. Building on the success of the SARLUX refinery based project in Italy to produce hydrogen and power, the Texaco gasification technology is now under final evaluation for several refinery/chemical facility applications, including the Shanghai Coking and Chemical Plant in China. This facility is developing a "trigeneration" project, of which two of the three legs are already operating. This single plant is designed to convert coal into methanol, electricity and town gas -- meeting three very distinct market needs -- cleanly, efficiently and with the flexibility to adapt quickly to changing market requirements.

3. Facility Integration -- Again, with the flexibility afforded by gasification's multiple feeds and multiple products potential, the ability to locate a gasification facility adjacent to, and therefore integrate the facility with, another facility (such as an existing refinery chemical plant or power plant) provides a significant opportunity for capital cost reduction and additional revenue steam generation.

4. Facility Financing -- Just as the applications for gasification technology are expected to become more complex, the methods of funding such projects are expected to be more sophisticated than the traditional model of corporate balance sheet financing. The financial community has already demonstrated its level of comfort on recent Texaco gasification power projects. Included in this success story are the financial closure of two refinery-based "project financed" transactions and one refinery-based "operating lease" transaction. Texaco is proud of its role, which included both technical assessment and commercial performance guarantees, in supporting the financial community in achieving these breakthroughs. And we clearly stand ready to continue this support for future projects.

5. Strategic Partnering -- It should come as no surprise that if the applications are expected to become more complex and the financing more sophisticated, there will need to be an evolution from the traditional project roles of owners/suppliers/etc. Teamwork among project sponsors to better manage the risk/reward profile for a gasification facility will become a must. Texaco's strategy, for example (and we know similar strategies are being initiated by other world class companies represented at this conference) emphasizes joint venture partnerships, and includes the active participation by Texaco in roles beyond the traditional perception of Texaco as technology supplier. The additional responsibilities we are pursuing when becoming an owner include responsibility for fuel supply, for operations/maintenance supervision, for establishment of maintenance programs, and for the supply of selected gasification technical support and equipment fabrication/supply. And we recognize that each of these roles must be performed to competitive standards and to bankable, contractual requirements.

The underlying theme to the facility of the future is its versatility -- using different, and multiple feedstocks to produce a host of products for different industry segments. Adapting technologies to these applications which are fully commercial will provide the most economic and efficient means of making these products from these materials, as well as being environmentally superior.

Thank you very much.

CONSOL'S PERSPECTIVE ON CCT DEPLOYMENT

F. P. Burke and R. M. Statnick
CONSOL Inc.
Research & Development
4000 Brownsville Road
Library, PA 15129

ABSTRACT

The principal focus of government investment in Clean Coal Technology must be to serve the interests of the U.S. energy consumer. Because of its security of supply and low cost, coal will continue to be the fuel of choice in the existing domestic electricity generating market. The ability of coal to compete for new generating capacity will depend largely on natural gas prices and the efficiency of coal and gas-fired generating options. Furthermore, potential environmental regulations, coupled with utility deregulation, create a climate of economic uncertainty that may limit future investment decisions favorable to coal. Therefore, the federal government, through programs such as CCT, should promote the development of greenfield and retrofit coal use technology that improves generating efficiency and meets environmental requirements for the domestic electric market.

INTRODUCTION

The CONSOL Coal Group, jointly owned by Rheinbraun and DuPont, produces about 72 million ton per year of steam and metallurgical coal and has reserves in most of the U.S. coal basins. Our mining operations are located in Canada, Kentucky, Illinois, Ohio, Pennsylvania, Virginia, and West Virginia. Domestically, CONSOL coal markets are east of the Mississippi River. Foreign sales include the Far East, the Middle East, and Europe. Because of the locations of our mines and our markets, we are particularly interested in environmental control technologies, including many of those being developed as CCTs.

Why is CONSOL qualified to speak about CCT deployment? CONSOL has supported coal-related research and development. We are the only U.S. coal company that supports a privately-funded coal research program. We have been active in supporting the DOE coal R&D program, including participating in four CCT projects: The Edgewater Boiler Limestone Injection and COOLSIDE Process Demonstration, The Milliken Clean Coal Project, the Micronized Coal Re-Burning Project, and the Piñon Pine IGCC Project. Our involvement includes financial contribution, direct participation to develop and evaluate process performance, and, in some cases, as a fuel supplier. As a coal-supplier, our goal in participating in the CCT program is to increase coal's market share of the electric generating market. The development of new technology may gain increasing importance as the deregulated utility market seeks the lowest fuel cost and capital cost for its electric generating systems. In addition to uncertainties due to deregulation of the electric utility industry, the generation-capacity owner, technology developer/marketer, and fuel supplier are facing uncertain environmental regulations. These environmental issues will create the potential for development and deployment of new CCTs.

Before proceeding, I would like to define what CONSOL means by Clean Coal Technology. Our definition includes retrofit and greenfield environmental control technology (wet scrubbers, low NOx burners, Selective Catalytic Reduction, and wide-plate-spacing ESPs), retrofit technology to improve cycle efficiency at existing plants (e.g., heat pipe air heater), and new power generation systems (e.g., PFBC, IGCC, advanced supercritical boilers, and the Kalina cycle) for greenfield or repowering applications.

During the remainder of my presentation, I will cover three main topics:

- Future of the power generation Industry
- Impediments to commercialization of clean coal technologies
- Need for government-industry partnerships

FUTURE OF THE POWER GENERATION INDUSTRY

The future of the power generation industry is uncertain. Utilities are buying and selling generating assets. The role of the IPP in the electricity generation market is unclear. Despite these uncertainties, one constant in any future utility scenario will be a focus on fuel price. The market will reward the low-cost producer and punish the high-cost producer. This will affect competition among coals, and particularly between coal and natural gas as the primary fuel for new electric capacity. Three issues drive the competition between natural gas and coal. They are:

- The efficiency of natural gas combined cycle units vs coal-fired systems
- The availability and price of natural gas
- Current and future environmental regulations

The natural gas combined cycle (NGCC) generating systems have significantly improved cycle thermal efficiency compared to simple cycle and first generation NGCC units. On a high heating value basis, the advanced NGCC generators have achieved 52 to 55% cycle efficiencies (at sea level and in new condition). The NGCC cycle efficiency is a function of elevation above sea level (cycle efficiency decreases by 0.3%/100 ft elevation), ambient temperature and age. The installed coal fired capacity in the United States has a cycle efficiency between 35 and 37%. CONSOL R&D developed the CONSOL Coal Quality Cost Model (CQCM) to evaluate the break-even price of coal and other fuels. The break-even price is the delivered natural gas price at which the bus bar power cost is identical for natural gas and coal. For the cost comparison, a new 500 MWe pulverized coal- fired power plant, complying with the NSPS for utility boilers and having a thermal efficiency of 36.2%, was compared to an NGCC plant complying with the Gas Turbine NSPS and having a thermal efficiency of 45.6%. Life cycle costs were estimated for different coal and gas prices, depending on the real inflation rate for gas prices. Figure 1 depicts the relationship between the break-even natural gas price (expressed as dollars per million Btu), the real inflation rate for natural gas, and the delivered coal price. For example, at an NGCC cycle efficiency of 45.6%, a current delivered natural gas price of $2.75 per million Btu, and a natural gas real inflation rate of 1%, the break-even coal price is $40 per ton. The impacts of NGCC and coal-fired cycle efficiency on the break-even coal price are illustrated below.

Effect Of NGCC Cycle Efficiency On Break-even Coal Price

NGCC Cycle Efficiency, %	Coal-Fired Cycle Efficiency, %	Break-Even Coal Price, per ton
45.6	36.2	$40.00
52	36	$34.00
52	42	$37.50

Assuming a 1% real inflation rate for the natural gas price and natural gas base price of $2.75 per million Btu, increasing the NGCC cycle efficiency by about 6% absolute reduces the break-even coal price by $6.00 per ton. Increasing the coal plant cycle efficiency from 36% to 42% at 52% NGCC cycle efficiency will increase the break-even coal price to $37.50/ton. The current average delivered coal price is about $33/ton.

This short discussion illustrates how NGCC and coal-fired boiler cycle efficiency, and the natural gas and coal prices will affect generation fuel selection.

Another topic that is being discussed is the rate of growth of utility generation. Many experts predict the future...most are wrong. That said, we will provide some estimates of future electrical load growth. Based on EPA telephone contacts with boiler owners and state regulatory offices, the projected 1996-2000 planned capacity addition is 5189 MWE.[1] The Energy Information Agency[2] estimates that electrical load will expand by 50,000 to 60,000 MWe through 2010. The increased demand for electricity will be filled by increased utilization of existing capacity, purchase of electricity from Canada and Mexico, repowering of existing units, and construction of new power plants. Repowered and new power plants could provide the markets to deploy CCT demonstrated generating systems (PFBC, IGCC, etc.).

IMPEDIMENTS TO DEPLOYMENT OF CCT TECHNOLOGIES

As I mentioned earlier, CONSOL markets coal worldwide. While our primary interest is the domestic market, CONSOL supports the worldwide deployment of CCTs to expand foreign markets. Expanding domestic and foreign markets will stabilize coal prices, increase the volume of coal exported, increase the volume of U.S. industrial exports, and help to maintain U.S. technological leadership.

I will now focus on domestic CCT installations and impediments to deploying CCT technology. As a coal producer, we are interested in retrofit CCT's which will be deployed beyond 2000 and in new, greenfield power installations for the post-2005 period. CONSOL believes that there will be three main impediments to deploying CCT technology. They are:

- Uncertainty concerning environmental regulations
- Uncertainty concerning power industry
- Coal-supply implications of new technology.

The U.S. power industry is facing a period of high uncertainty concerning the future of environmental regulations. EPA is considering the following environmental regulations:

Pending Environmental Regulations

National Ambient Air Standard for SO_2
National Ambient Air Standard for Ozone
Revised New Source Performance Standard for Utility Boiler NOx Emissions
NOx Emission Limits Due to the Ozone Transport Assessment Group
NOx Emission Limits Due to OTC Regulations
Nation Ambient Air Standard for $PM_{2.5}$ (2.5 µm Particulate Matter)
Utility Air Toxics Regulations

The three ambient air standards could require utilities to reduce NOx and SO_2 emissions from existing utility boilers through the State Implementation Plans. If the cost of compliance is not excessive, these regulations could create a market for the retrofit CCTs. For example, the CCT program demonstrated the performance and economics of the Pure Air , Chiyoda, and SHU FGD processes for SO_2 control; of the NOxOUT, Selective Catalytic Reduction, and low NOx burners for nitrogen oxide control; and wide-plate spacing ESPs for particulate control. The OTC and OTAG processes could create a market for NOx control technologies capable of achieving emissions of 0.15 pounds-per-million-Btu. Clearly, EPA's actions will either expand the market for CCTs or, if the environmental regulations are too severe, they could reduce coal-fired generation and the demand for CCTs.

I have been informed that the utility deregulation legislation being drafted by DOE may include an environmental compliance title. It was reported that EPA is seeking significant SO_2 and NOx emission reductions beyond Title IV Acid Rain Control levels. DOE and EPA are discussing a concept termed “environmental comparability”. While the definition of "environmental comparability" is not clear at this time, it could mean that existing SIP-regulated boilers become subject to the New Source Performance Standard after a certain operating life. There is much economic uncertainty due to deregulation. Adding an uncertain environmental burden only increases this uncertainty.

Not on the list of pending regulations is greenhouse gas control. A program to limit greenhouse gas emissions without including the entire community of nations is doomed to failure. Several countries have already stated that they will not participate in greenhouse gas emission control. Many third world countries are purchasing the standard 2400 psi, 1000 °F/1000 ° F boiler. The third world is where the growth in greenhouse gas emissions will occur. China is currently the world's leading coal consumer. The Chinese are purchasing the standard boiler package and have stated that they will not agree to greenhouse gas limitations. Reducing CO_2 emissions will limit coal and, for that matter, any fossil fuel usage. Increasing power plant efficiency will reduce CO_2 emissions per kilowatt generated, but may not reduce the total CO_2 emissions if there is compensating growth in generating capacity.

Regardless of the post-deregulation future of the power generation industry, there will be a shakeout period. As stated above, the low-cost power producer will be the winner. The role of CCTs in this market is not clear. The uncertainty in the nature of the generation business will limit capital expenditures over the short term. The initial impact of deregulation is to minimize capital investment. Only absolutely needed generation will be purchased. The initial choice will focus on low capital cost systems with short payback periods. As the future becomes clearer, the generation owners will begin to focus on least-cost, life-cycle processes. In this market, coal will continue to be an important player. CCTs can capture a portion of the new generation capacity market (2005 to 2015) if they can demonstrate cost-effectiveness, reliability, and generating capacity flexibility.

The impact of coal quality specifications on CCTs has not been clearly defined. Will all coals perform equally well with a given CCT? What are the impacts of ash fusion temperature, coal chlorine content, ash content, volatile matter, etc., on CCT process performance? These issues have not been resolved for all economically attractive coal basins.

NEED FOR CONTINUED FEDERAL ASSISTANCE

CONSOL believes that government involvement in the development of technology should be minimized. However, the combination of regulatory and environmental uncertainty caused by past and potential future federal actions has changed the private sector risk analysis. Typically, when a company evaluates a development project, it evaluates the market size and the cost and performance of current technology. For example, Intel knows the cost and performance of both its current generation and the competitors’ microprocessors. Developing a new microprocessor has risk, but the market size and new performance requirements can be estimated with some accuracy. Compare this to developing power systems. What is the performance requirement? The EPA can alter the performance specification by imposing additional requirements that are out of the control of the process developer. If the developing design includes a 90% NOx removal but EPA regulations require 95%, then the development effort may be in vain. A significant uncertainty is greenhouse gas emission reduction. What is a minimum acceptable boiler efficiency that might satisfy EPA requirements? No one can answer that question.

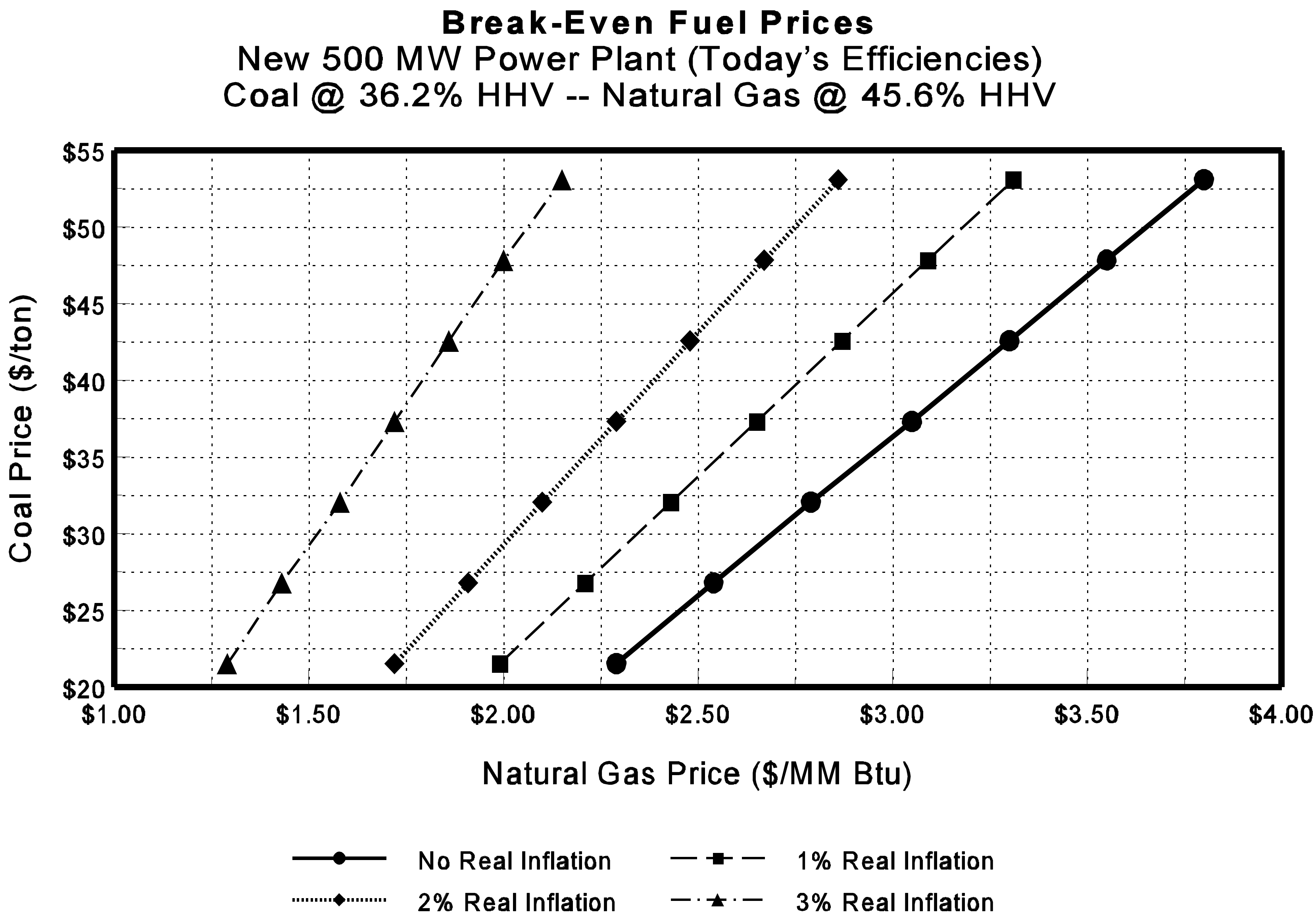
When regulatory uncertainty introduced by the federal government has such significant impacts on technology development, then the government has a responsibility to assume a portion of the development risk. The Clean Coal Technology Program was an example of a private sector-federal program which achieved some success. Some have complained that this was a welfare program for industry. This is far from the truth. For example, CONSOL, Babcock & Wilcox, DOE, and EPA developed low capital cost, moderate SO_2 removal processes. When the Clean Air Act Amendments of 1990 were passed, Title IV (Acid Rain Control) did not favor these technologies because of the utility-wide emission allowance and trading programs. The private sector and federal investments were made obsolete by the Congress and EPA's implementation of the Act. This situation continues to exist today and probably will continue to exist in the foreseeable future.   If the United States is to remain a leader in power systems development, continued federal assistance will be required to domestically deploy CCT-demonstrated NOx and SO_2 controls and more efficient coal-based power systems such as PFBC, IGCC, the advanced supercritical boiler, the Kalina cycle, and others.

One final point. Ultimately, the decision about federal investment in energy technology should reflect the goal of providing power to the domestic consumer at lowest cost consistent with environmental objectives. In this sense, the success of the CCT program should be judged by how well it speaks for the energy consumer. The objective of the CCT program is to demonstrate lower cost, environmentally-compliant technologies to increase the use of inexpensive, abundant coal, and to leverage the government investment through private-sector cost sharing. A successful CCT program keeps the cost of electricity low, which benefits industrial, commercial, and residential users. I believe the CCT program can stand on its record in addressing the two demands of the energy consumer: low-cost electricity and environmental protection.

REFERENCES

1. J. Eddinger, EPA personal communication

2. Energy Information Agency, *Electric Power Monthly*, March 1996, and *Short Term Energy Outlook*, April 1996.



Break-Even Fuel Prices
New 500 MW Power Plant (Today's Efficiencies)
Coal @ 36.2% HHV -- Natural Gas @ 45.6% HHV
Coal Price ($/ton)
$55
$50
$45
$40
$35
$30
$25
$20
$1.00
$1.50
$2.00
$2.50
$3.00
$3.50
$4.00
Natural Gas Price ($/MM Btu)
No Real Inflation
1% Real Inflation
2% Real Inflation
3% Real Inflation

STATE PERSPECTIVES ON CLEAN COAL TECHNOLOGY DEPLOYMENT

Terri Moreland, Director
State of Illinois Washington Office

ABSTRACT

State governments have been funding partners in the Clean Coal Technology program since its beginnings. Today, regulatory and market uncertainties and tight budgets have reduced state investment in energy R&D, but states have developed program initiatives in support of deployment. State officials think that the federal government must continue to support these technologies in the deployment phase. Discussions of national energy policy must include attention to the Clean Coal Technology program and its accomplishments.

I. INTRODUCTION

I'm pleased to be a part of this panel to represent the states' perspectives on the future of Clean Coal Technologies. Before I begin, I would like to thank all of the state officials who took time to talk to me about their views and activities.

States have been active partners in the Clean Coal Technology Program since its beginnings. Of the 40 projects funded through the program, 15 received support from state governments or state universities. The states of Alaska, Ohio, Pennsylvania, Indiana, Illinois and New York and the universities of Georgia and North Dakota all have participated in Clean Coal projects. Ohio alone was a funding partner in six projects, and Illinois and Pennsylvania supported two projects each. States provided only about 3% of total program funding, but their participation was crucial in building political and funding support for many of the co-funded projects.

It's always been clear that the participating states perceive they have something to gain from the commercial development and deployment of Clean Coal Technologies. The states' role in Clean Coal Technology development has been a parochial one, aimed at fortifying specific economic strengths as well as providing long-term energy and environmental benefits to their citizens.

When the Clean Coal Technology program began in 1985, there was a very different culture in states than the one that exists now. At that time, a typical debate in my state legislature involved which tax to raise, how to come up with a dedicated funding stream, how much more bonding authority to approve -- basically, how to get the money to pay for more and bigger programs.

Coal development programs enjoyed strong political and funding support in a number of states even before the federal Clean Coal Program was established. In Illinois, for example, we had already cofunded several technology demonstration projects by 1985. We were embarking on a series of industrial-scale demonstrations using advanced fluidized bed combustion systems. We were developing a demonstration of the Chiyoda scrubber at the University of Illinois. We had just received funding for a major coal R&D effort, in addition to participating in the national Clean Coal Technology program. Clean energy was a real priority in state and national programs and policies.

Ten years later, states are still interested in clean coal technologies, but there have been some fundamental changes in the type and amount of support that states provide. I'm going to briefly discuss some of the challenges states face and how they have influenced state activities.

II. CHALLENGES

Many speakers over the last few days have cited the challenges facing Clean Coal Technology deployment: emerging environmental issues, electric utility deregulation, the current excess capacity in domestic utility markets, the dynamic relationship between coal and natural gas, the costs and status of technology deployment, et cetera. All of these factors have undoubtedly influenced the decisions of all of the participants in the Clean Coal Program in some respect.

The unique differences between states make it difficult to talk about a "generic" state outlook or response. From the state perspective, it makes sense to look at these challenges in a kind of aggregate way, and you can boil them down to two central forces: The first is a kind of "uncertainty factor," related to all of the regulatory and market issues that other panelists have discussed. The second is related to the budget problems that states are experiencing. These forces together have changed how states see their role in any future technology deployment initiatives.

Everyone here understands the regulatory and market issues. As of June 30, 1996, regulatory commissions in 44 states had adopted or were evaluating utility deregulation alternatives, according to a study by the General Accounting Office. There are at least 12 deregulation bills in the works in Congress, although it's still unclear whether legislation will advance during this session. Illinois' Office of Coal Marking and Development has produced a white paper on the effect of utility restructuring on our state, with specific attention to impacts on the coal industry. The paper predicts several major changes in utility operations, including consolidation, a switch to performance-based regulations, and the development of regional power pools. It also predicts that with an emphasis on efficiency, existing coal-fired power plants will increase production in the short run due to their lower marginal generation costs. Over the longer term, however, the older, less efficient plants will be retired and replaced with or converted to natural gas. Other states have similar predictions, although there is an emerging body of experts who believe that gas-fired, highly efficient "micropower" plants will supplant utilities as we know them by the end of the next decade. In either scenario, the outlook for new coal use technologies is uncertain.

The impacts of change in environmental regulations on the coal industry are well documented. In 1985, the FOB price of Illinois coal was $30.80/ton; a decade later, the price had fallen 29%, to

$21.80/ton. Mine employment dropped 67% over the same period. Electric utility purchases of Illinois-mined coal fell 25%, from 54.5 million tons to just over 41 million tons. Ohio, Pennsylvania, Indiana, and Kentucky -- the states traditionally most active in coal research and development -- all experienced similar decreases. Meanwhile, exports to the Midwest from the Power River Basin reached an all-time high. Still to come, of course, are the impacts of Phase II of the Clean Air Act. In the environmental arena in particular, uncertainties are driven by forces that are external to state government and it's difficult for states to formulate meaningful technology policy in response.

Then there's the fiscal challenges to states. Over the last decade, states have increasingly had to cope with a structural imbalance between the rate of growth of state revenues and the rate of growth of expenditures. This imbalance has affected every state in some way and it's almost all due to increases in the costs of Medicaid, which pays for health care for the poor and elderly. From 1990 to 1995 these costs -- which are mandatory entitlements -- grew by almost 20% per year, while state revenues increased by about 5% a year.

Today, these Medicaid costs make up 20 to 30% of our state budgets. In Illinois alone, the tab is $6 billion a year. It's impossible to argue that this is not a priority, yet every single other state initiative -- education, child welfare, prisons, mental health, law enforcement, as well as energy and environment and economic development -- has been affected. In the 1990s, states have stopped looking for new ways to spend money, because we are told how we **must** spend it.

Governors and state legislatures have not been inclined to raise revenues to make up the difference. In fact, according to the most recent *Fiscal Survey of the States*, a report produced annually by the National Governor' Association and the National Association of State Budget Officers, 35 states actually decreased taxes in some way last year, continuing a trend that started in the early 1990s.

The regulatory and market uncertainties combined with serious fiscal constraints have led, directly or indirectly, to changes in state programs. In August 1996 *Governing* magazine reported that many states had closed or restructured their energy offices. In fact, Washington, New York, Pennsylvania, Illinois, Mississippi, North Carolina and Tennessee have all recently consolidated their energy programs into larger departments. In the last 6 years, the number of employees in state energy offices has fallen by an average of 14.5%, according to a survey by the National Association of State Energy Officials.

State funding for energy R&D has also declined. In 1995, the General Accounting Office looked at changes in electricity-related R&D for technologies cited by a Secretary of Energy task force as having high and medium long-term potential for meeting national energy goals, including fuel cells, coal gasification and advanced turbines as well as alternative energy technologies. The report noted that "of the 11 large (R&D) programs in the nine states reviewed, 7 have been reduced in the last three years." Overall, the GAO study found a 30% reduction in state funding for advanced power generation R&D, from $83 million to $58 million, over the two year period surveyed.

I should also note here that the federal government and electric utilities also reduced R&D funding over the same period. Overall tight budgets and the increased competition expected from utility deregulation were cited as the principal reasons for declining support.

III. STATE ACTIVITIES

The good news is, even though programs have been downside and restructured, there is still a significant amount of state activity and interest in the support of coal and clean coal technologies. The state energy officials that I interviewed consistently cited a sharpening of goals in their programs and a feeling of greater accountability in setting economic development priorities.

In those states that have traditionally pursued clean coal technologies and coal development, the approach today appears to have shifted from big incentives for major development projects to more pragmatic, focused actions such as exploration of niche markets, promoting export opportunities, technical assistance and education.

There is one notable exception to this generalization. Mississippi, one of a handful of states projected to need new generating capacity, is undertaking a major lignite development project that will likely use an advanced, clean technology. Last year, the Mississippi state legislature expanded the scope of general obligation bonding authority and earmarked $30 million toward the development of a 400 MW lignite-fired generating plant and associated industrial complex, diverting bonding authority previously earmarked for the Strategic Petroleum Reserve. A coal company, electric utility and the state and local government are partnering in the project, which is still in its developmental stages.

In Kentucky, a state with a long history of support for coal research and technology projects, state officials have made a decision to focus their efforts on education at the elementary school level. Bill Grable, director of the Kentucky Coal Marketing and Export Council, plans to personally visit public schools throughout the state to bring students the message of the importance of coal to the state economy and the opportunities for environmentally sound coal use.

Pennsylvania has restructured its energy office and put it in the state Department of Environmental Protection. The Pennsylvania Energy Development Authority no longer exists as an active R&D organization. The new Department of Environmental Protection has become business-friendly, according to state officials, and has created the Office of Compliance Assistance to work with companies on pollution reduction. This would include assistance in planning for advanced technology retrofit projects.

In Ohio, the state is exploring niche markets for coal, including industrial projects. Ohio appears to be the only state where programs are specifically configured to promote Clean Coal Technology deployment. The Ohio statute allows state funding for up to three replications of a first-of-a-kind technology. Other states might consider such a statute to allow for participation in the deployment phase.

Illinois has a number of major projects ongoing. The state has also undertaken specific activities relevant to the deployment of Clean Coal Technologies, including the development of an interactive, computer-aided design package for State of the Art Power Plants using advanced technologies. Illinois is also supporting a series of workshops to bring together technology manufacturers and electric utility operators to share solutions to changing environmental standards. In addition, Governor Edgar has recently announced a multi-million dollar plan to expand markets for Illinois coal and improve the state's coal transportation, export and delivery systems. Our Lieutenant Governor, Bob Kustra, has formed a Coal Strategy Group to explore ways to improve the economic viability of Illinois coal. The group is made up of leaders of the Illinois Coal Association, the United Mine Workers of America and several state agencies. The Coal Strategy Group has been active in development of legislation to support the state's coal industry.

IV. THE NEED FOR LEADERSHIP

Realistically, individual states will not make much of an impact on Clean Coal Technology deployment in the near term. State energy officials are highly supportive of deployment, and they think that these technologies merit continued federal support and leadership in the deployment phase. Federal tax incentives, expedited permit protocols, targeted export assistance and graduated support for successive replications were some of the ways that states suggested to help promote commercial deployment.

It's interesting to note that one regional organization, the Southern States Energy Board, has established an effort to promote the increased use of U.S. coal and the transfer of Clean Coal Technologies. SSEB's activities include participation in major coal forums to serve as a focus for state interest in Clean Coal Technologies, facilitating discussions of market development and penetration potential for these technologies, and identifying institutional barriers to their use. Other states might want to join forces with SSEB or organize their own regional effort.

State officials also stressed the importance of raising the profile of the program at the national level. The Clean Coal Technology program has not received nearly enough credit for what it has accomplished. I'm not being critical of the federal Clean Coal program leadership, because they've done an admirable job of keeping interested parties informed about its accomplishments. States are concerned, however, about the lack of attention to this program in national policy, and beyond that, the lack of attention to any coherent policies that incorporate realistic energy goals.

Our national political leaders seem to spend a lot of time hyping things like public-private sector cooperative efforts, development of emerging markets for technologies, export opportunities, building national excellence, and promoting environmental quality. These are all attributes of the Clean Coal Technology program. It should be recognized as a model initiative and the embodiment of important national policy goals. We are taking a lot of rhetorical and actual pride in our ability to get things done, but, as far as energy is concerned, there is very little attention given to what it is we should do and why we should do it.

REFERENCES

Clean Coal Technology Demonstration Program: Program Update 1995, U.S. Department of Energy, Washington, DC, April, 1996.

Illinois Coal Industry White Paper: Understanding Electric Utility Restructuring, Illinois Department of Commerce and Community Affairs, May, 1996.

Key Numbers in the Illinois Coal Industry, Illinois Department of Commerce and Community Affairs, June 25, 1996.

"PRB Production to Top 300 Million Tons," *Coal Outlook*, December 9, 1996, p.1.

The States Forge Ahead Despite Federal Impasse, Council of Governors' Policy Advisors, February, 1996.

The Fiscal Survey of States, National Governors' Association/National Association of State Budget Officers, November, 1996.

"States Are Pulling the Plug on Their Energy Offices," *Governing*, August, 1996, p. 47.

Federal Research: Changes in Electricity-Related R&D Funding, United States General Accounting Office, August, 1996.

Lieutenant Governor Bob Kustra, "Marketing Illinois Coal," *Rural Horizons*, October/November, 1996, p. 1.

COMPLETING THE CCT MISSION: THE CHALLENGE OF CHANGE

James R. Monk
President
Illinois Energy Association

Fifth Annual CCT Conference
Tampa, FL
January, 1997

I. INTRODUCTION

Thank you for the opportunity to provide some insight on the future of clean coal technology and how the CCT mission might be completed in a restructured electricity industry. A few years back, I spoke at this conference when it was held in Cleveland. At that time I was a regulator and before that a legislator. I hope to draw upon those prior experiences, add a perspective from my current role as an energy industry association executive, and suggest some ways in which we can all work together to meet the challenge of change consistent with the theme of this meeting.

First, I hope you will indulge me the opportunity to tell you a little about the Illinois Energy Association. Our organization is relatively new, having been formed in January 1994. We have eight member companies who are investor-owned energy utilities doing business in the State of Illinois: Central Illinois Light Company, Central Illinois Public Service Company, Commonwealth Edison Company, Illinois Power Company, Interstate Power Company, MidAmerican Energy Company, Mt. Carmel Public Utility Company and Union Electric Company. Our members run the gamut from a heavy concentration of nuclear generating capacity to exclusive use of coal for generation. Each year we use millions of tons of coal, both high-sulfur Illinois Basin and low-sulfur. The member companies of the Illinois Energy Association are not only interested in the future of clean coal technology, we have a huge stake in its viability.

My personal involvement in clean coal technology spans my changes in career. As an Indiana State Senator representing a coal belt district, I was deeply involved in pro-coal legislation and was an author of Indiana's 1989 statute promoting the use of clean coal technology. When I left the legislature and became Chairman of the Indiana Utility Regulatory Commission in May of 1989, one of my first tasks was to interpret and implement that very law which I had just authored. That case resulted in construction of the Pure Air on the Lake project at Northern Indiana Public Service Company's Bailly Generating Station. Later I was involved in approval of construction for PSI Energy's Wabash River Coal Gassification Repowering Project. Since leaving the Indiana Commission in 1993 for my present position, I have been involved in helping my member companies monitor clean coal technology developments. I was born and raised in Sullivan County in Indiana's coal belt, and much of my public and private career has been devoted to promoting coal and clean coal technology.

Permit me also to say a word about coal and the State of Illinois. We are deeply involved in coal development for many reasons, but especially because of the fact that there is more energy in Illinois coal deposits than in the oil reserves of Saudi Arabia and Kuwait combined. From the earliest days of the state, coal has not only fueled the homes of Illinois residents and the state's economy, but it has been woven into its social fabric.

The State of Illinois and the state's coal mining industry have long acknowledged the problems inherent with mining and burning coal. But, more importantly, they are actively and vigorously seeking new technologies to ensure that coal plays an important role in Illinois' future.

Long before clean air and acid rain become important public issues, Illinois was leading the way toward the development of new technologies to burn coal more cleanly, more efficiently and less expensively. Illinois, in fact, is a leader in the development of clean coal technologies.

Coal is mined on an immense scale in our state. Altogether, some 54 million tons a year are recovered from beneath the rock and soil of Illinois. Both surface and underground mining are done on a scale that astonishes those who view it for the first time.

Unlocking the secrets of clean coal technologies is done on the other end of the scale. It begins with the molecular structure of coal. Researchers probe the basic organic nature of this fossil fuel to help other scientists — and later, utility and coal industry engineers — understand how to make coal a cleaner fuel for the 21st century.

The search for answers on how to burn Illinois coal, which is naturally high in sulfur, without releasing unacceptable levels of sulfur dioxide into the air has been going on for decades.

The effort is under way in the laboratories of major Illinois universities, in the demonstration projects managed by the state's utilities and large industries, by researchers working for the state's coal companies and through special programs operated around the state. This massive effort is coordinated by the Illinois Coal Development Board and the Illinois Department of Commerce and Community Affairs, which administers the state's research, development and demonstration programs. In 1984, the Illinois General Assembly established the Coal Technology Development Assistance Fund to speed the transfer of successful laboratory experiments into full-scale demonstration projects. To date, the Board has approved nearly $42 million for laboratory research through the Illinois Clean Coal Institute.

Since 1975, the Illinois General Assembly has authorized $183 million in Coal Development Bond funds for the Illinois Coal Demonstration Program, of which the Board has committed $138 million on 18 clean coal technology projects. The state money has been matched with nearly $662 million in public, private and federal funds for these projects.

Illinois believes that coal is a fuel for the 21st century, both by necessity and by technology. From the standpoint of necessity, coal is our most abundant natural resource, giving America literally hundreds of years of supply.

From the technological perspective, advances in research — fostered by the Illinois Coal Development Board, the Office of Coal Development and Marketing and the Illinois Clean Coal Institute — are proof of the reality that coal's bright past is but a prelude to coal's bright future.

II. CCT AND INDUSTRY RESTRUCTURING

The thrust of my remarks today is this: In order to "complete the clean coal technology mission" it will be necessary to determine CCT's role in the restructured electricity industry and develop a strategy to promote that role. First, we must understand where the industry is headed and how clean coal technology fits into that future. Then, we need to develop a strategy for getting from here to there, from where CCT is today to where it must be in five, ten or twenty years to be a viable option for decision-makers.

Trying to determine the details of where the nation's electricity industry is headed is an especially difficult task at this point in time. In fact, it has developed into a real growth industry if the number of conference and seminar brochures which arrive daily at my office are any indication. But one need look no further than the halls of the state legislatures and the Congress to find guidance. For the first time in nearly a century, the fundamental order of the industry is being changed by those who set it in place originally, our elected representatives. In Illinois, as in California, Rhode Island and any number of Statehouses, the General Assembly is beginning to take up industry restructuring legislation as we speak. The Congress is also poised to take up the subject. The laws which are passed in Washington, Springfield and elsewhere will provide the statutory roadmap which leads eventually to a fully competitive electricity industry where every customer has the power to choose his or her or its electricity supplier. While important, the timing of this move is not nearly as critical as the fact that it absolutely, positively will occur.

One of the most critical parts of my job is to demonstrate to people at my member companies who have been in the industry for many, many years that this change is coming, it is positive and that it will fundamentally alter the way their companies operate. The phrase I often use in a shorthand way to try to describe this sea change is that we will soon become an industry where the bottom line is actually the bottom line. That concept has lots of implications for every stakeholder in the industry but it has particular implications for those of us interested in promoting clean coal technology. When I say that we need to determine how clean coal technology fits into the future of a restructured industry I mean above all how does it fit in terms of "cost." Because that little four-letter word "cost" will soon play the same role in our industry as it does in every other competitive industry, a role which it has really never before played for us. We can talk all day long about the abundance of coal and how using coal to fuel the next generation of power plants would be in the common good, but believe me all the strong policy arguments won't amount to much if clean coal technology is not cost-competitive with other sources. When we say that CCT will be a superior technology at the time these decisions are made, we must include superiority from a cost-effectiveness standpoint in that definition.

Clearly, clean coal technology does not meet that standard today. How, then do we get from here to there? What is our strategy as promoters of clean coal technology as the power source of choice for the next generation? Who does our strategy target in terms of decision-makers? Perhaps, this final question is the place to begin because the answer on a long-term basis will be quite different than it has ever been for the industry. For the first time in its history, the electricity industry itself will be required to assume the risk and make such decisions. And all without any of the old, reliable safety net found in the regulatory model. In the coming market economy, electricity industry decision-makers will find that the market itself will set the parameters of their decisions and that those parameters, as in all competitive industries, will be largely based on costs. It is nearly impossible to underestimate the change in industry corporate culture needed to digest this shift in priorities.

Thus, the crux of any strategy for promoting clean coal technology as a viable choice for industry decision-makers must lie in making CCT cost-competitive with other potential power sources. Reaching such a goal will not be easy but it is not impossible. It can be accomplished by forging a collaborative effort on the part of the stakeholders who would benefit from use of clean coal technology: electricity consumers, federal and state governments, electricity suppliers of all stripes, CCT developers and vendors, and those directly involved in the production and sale of coal itself. And in this latter group I would certainly include those whose jobs either directly or indirectly depend on coal. One of the increasingly vocal stakeholder groups in the electricity industry restructuring debate is that representing the utility workers. Coal miner representatives must be a vital part of any clean coal technology collaborative effort.

Together, these diverse groups have a great deal of political clout if they will only work in a coordinated fashion to use it for this purpose. Various types of incentives which would help to spur research and development of clean coal technology can be achieved at both federal and state levels if we all work together toward that goal. To be cost-competitive in the long run when decisions will be made regarding new sources of generation, clean coal technology must have already progressed through the testing stage and the application stage of development so that it is approaching maturity status as a market. Only then will it pass the kinds of cost-effectiveness tests which will be used by the market to make final choices. Clean coal technology must be ready when the time is right; it cannot afford to be late, because as my industry is about to learn, in a market economy as in politics, timing is everything.

Policy decisions which benefit the development of clean coal technology will not be made in a vacuum and they will not be made out of altruism. They will be made by down-to-earth policymakers engaged in a political process which is the lifeblood of our society. If we who favor deployment of clean coal technology sit back and wait for policymakers to discover the wonder of our product by their own devices, it will be a very, very long wait. We must mobilize our considerable resources and actively promote our agenda if we have any hope of success for CCT.

III. CONCLUSION

Coal makes sense for the United States. It makes sense for several important reasons not the least of which is its abundance here — we are the Persian Gulf of coal. It also makes sense in terms of its economic impact on large areas of our nation. And if coal makes sense, especially economically, then clean coal technology makes even more sense because of its potential to capitalize on this abundant resource in an environmentally friendly manner. But I am here to testify that after nearly thirty years of involvement in the political world at all levels from Washington, D.C. to Washington, Indiana, I have learned the hard way that "common sense" does not always, or even often, carry the day in the policymaking process. I believe that the future of clean coal technology hinges on our ability in the next few months and years to mobilize all those who favor that technology to move forward in a cohesive and coordinated effort to affect the policymaking and political process and thereby promote and accelerate CCT development. If we can do so, then we are well on the way to completing the clean coal technology mission and meeting the challenge of change.

INTERNATIONAL MARKETS: SEIZING THE OPPORTUNITY

Alan Heyes
Energy Technologies Directorate
UK Department of Trade and Industry

Fifth Annual Clean Coal Technology Conference
Tampa, Florida
January 7-10, 1997

Chairman, before I get started on my presentation I would like to congratulate the US Department of Energy for having the considerable foresight in establishing the clean coal demonstration programme when it did.

While many speakers over the past few days have highlighted the challenges of bringing forward the take-up of clean coal technologies, without the US Department of Energy Clean Coal Demonstration Programme the challenge would be near impossible to reach and the long term consequences on the environment substantial. In addition the guidance and inspiration it has given to more modest clean coal programmes overseas cannot be underestimated. I know from personal experience that the UK Department of Trade and Industry and UK industry has found our contacts with the programme invaluable.

To start off my analysis of the presentations, I would like to highlight some of the key facts and figures mentioned in a number of papers this week, together with a summary of the perceived market barriers.

Firstly, a number of presenters have referred to the expected continued rise in coal demand for power generation and other uses for the foreseeable future - certainly well into the 21 century. Forecasts by the International Energy Agency highlighted in John Ferriter's presentation on Wednesday indicate a substantial increase in world coal demand to 2010. Rising from around 3.5 billion tones at present to over 5.3 billion tones by 2010. As we heard from David Gallasby yesterday, most of this increase is in Asia, where coal demand in China alone is set to increase from 1 billion tonnes to over 2 billion tonnes and in India from 250 million tonnes to 500 million tones by 2010. These figures demonstrate the substantial economic growth expected in Asia over the next few years and perhaps indicates where much of our effort to promote clean coal technology should really be focused.

There is a clear consensus on what the barriers to bringing forward any significant amount of advanced clean coal technology at the present time. These are:

- uncertainty associated with a deregulated electricity industry and a highly competitive market place

- increased availability and competition from natural gas

- in many countries the electricity utilities have only just been privatised and are particularly risk adverse

- lack of commercially demonstrated performance and perceived cost competitiveness, particularly for IGCC and PFBC

- the public and political perception about coal

- the concern about even tighter environmental constraints

- the financial constraints and technology risk premiums

A number of presenters have touched on the issue of coal being perceived to be a “problem fuel” associated with global warming and local pollution acid rain and particulates. This is despite the wealth of publications and information about the benefits of clean coal technologies produced over the past few years by various public and private agencies in the US and overseas.

The increase in coal use should not be seen only as an environmental problem to solve, but a major market opportunity for exporters of technology, components and know-how - in both the United States and internationally. A recent study by the IEA Working Party on Fossil Fuels has shown that the potential market for clean coal technologies exceeds $800 billion over the next few years to 2010. 90% of which is related to power generation. This $800 billion forecast is close to the trillion dollar figure quoted by Mrs Patricia Godley on Wednesday.

Seizing this huge market opportunity is the real challenge. If we are successful (I say we for this market is large enough for everyone to have a share),it would make a substantial difference to the environment of the certain increase in coal use over the next few decades.

It is also important here to understand that clean coal technologies can also mean “state of the art” conventional plant. Such plants offer substantial improvements in both efficiency and environmental performance when compared to many existing plants in both the United States and the rest of the world.

We should not necessarily be too pessimistic about not being able to speed up the deployment of advanced clean coal technologies as fast as some speakers this week would like. In my view the worst possible outcome for advanced clean coal technologies such as IGCC is if a technology is sold to a utility or IPP on the basis of certain performance criteria and it fails to deliver. While this is obviously a major problem both financially and technically for the technology supplier, it is also immensely damaging to other clean coal technologies approaching commercialisation. As Larry Papay of Bectel mentioned during his luncheon address on Wednesday, some technologies will inevitably fall by the wayside; what we must not do is make some of them fall off the road because we pushed them to quickly.

The Coal Industry Advisory Board study which John Wootten outlined on Thursday provides an invaluable status report on where we are with deploying clean coal technologies. In particular, it set out the policies and measures that might be deployed to overcome some of the barriers.

The presentations from John Wootten and David Gallasby, did indicate to me a considerable interest by utilities to take up more advanced clean coal technologies if manufacturers could deliver on price, availability, and reliability etc. As Ian Torrens presentation highlighted, the fact we have 350 supercritical units operating or planned throughout the world now, and that some utilities are prepared to take the risk and become involved in first of a kind plant both here in the United States and in Europe, Japan etc., albeit with some public funding in one form or the other, is very encouraging. Clearly it would be immensely beneficial both to the environment and to industry if the more advanced technologies could be taken up commercially at a faster pace both at home and overseas.

Having listened to, and read the papers presented on Thursday, I believe there are a number of positive things we can do to smooth the path of encouraging the deployment of clean coal technologies over the next few years. It will require careful planning, and a willingness of all those with an interest in seeing clean coal technologies adopted as the energy technologies of choice in the 21st century, to work together much more closely than at present. Many of the activities could turn out to involve little if any additional work and may even lead overall to less effort if there is a commitment to work together.

Firstly, we need to be much more focused and concentrate effort in a few key growth areas such as China and India. The UK for example is focusing its export activities on clean coal technology on India and just one or two provinces in China.

Secondly, there is growing evidence that a number of countries have been confused by the conflicting information and advice they have received about clean coal technologies. This confusion and lack of knowledge also persists in those countries leading technology development. I have met for example a number of senior energy company executives in the United States who were unaware of the breadth of the US Clean Coal Demonstration Programme. Mrs Patricia Godley has quite rightly emphasised the importance of educating key players in the United States together with the general public.

There is always a danger we produce information only for ourselves, It is vital we remember key decision makers at home and abroad and the public have their own, often very specific information requirements. The importance of preparing appropriate information and disseminating it effectively was emphasised by John Wootten in setting out the CIAB’s recommendations on policies and measures to overcome barriers.

These CIAB recommendations' emphases the importance of the private sector and government working together to disseminate technical and economic information about clean coal technologies including supercritical and ultra supercritical technology.

I would strongly endorse this but recommend this is done under the auspices of the International Energy Agency as part of the World Bank clean coal initiative. I would also recommend we make particular use of the IEA Clean coal Centre (formerly known as IEA Coal Research) for this work.

Thirdly, there is a need for a consensus on what are the main barriers to technology deployment within individual countries and prepare a strategy to overcome them collectively. Again, this could form part of an international collaborative activity under the auspices of the IEA.. It cannot be effective and efficient to try and open up new markets to deployment and reduce tariff charges etc., in a random way as currently undertaken.

Three final points. There are clearly no easy solutions to overcome some of the perceived impacts of deregulation, privatisation and competition to the take up of clean coal technologies. As David Gallasby reminded us on Thursday, what is most important is market pull, assisted to some extent by improved information dissemination on benefits of clean coal technologies.

The US Department of Energy may wish to consider for its next conference to have a specific session devoted to reporting progress on overseas demonstration projects. This would allow within the scope of one conference for us to see the “state of the art of world development of clean coal technologies., and further demonstrate the commitment of the United States, Europe and Japan etc., to work together to enhance information dissemination.

Finally, accepting market pull is essential to the future deployment of clean coal technologies, the US Department of Energy should consider inviting representatives from the key market areas - decision makers, technical and financial advisers etc. to tell us what information they require with respect to clean coal technologies. Such action should greatly assist the US Department of Energy in focusing its future activities more effectively.

ROLE OF CCTs IN THE EVOLVING DOMESTIC ELECTRICITY MARKET

THOMAS J. GRAHAME
SENIOR POLICY ANALYST
U.S. DEPARTMENT OF ENERGY

I. KEY POINTS AND ISSUES

(1) Panel considered the effects of deregulation of electricity markets on CCTs, with CCTs defined as greenfield and repowering technologies, in the medium to long term

(2) Full fledged consumer choice likely won't occur for at least five years, perhaps more, but there are at least two important impacts today for CCTs:

(A) Uncertainty: don't know what costs can be recovered in long run, so even more incentive (e.g., in addition to present overcapacity) to minimize new construction

(B) Huge incentive to cut costs everywhere: *any missed opportunity to reduce costs in new, deregulated environment automatically translates to lost profit (or losses instead of profit).* Main impact of deregulation on CCTs is probably pressure to reduce construction costs

(3) Impediments to CCTs being cheapest option:

(A) Natural gas prices are low and projected to increase only slowly (EIA projects about 1% annual increase in excess of inflation through 2015);

(B) Capital costs for CCTs (and coal generally) are too high; and

(C) CCTs are still perceived as riskier than more commercial technologies, and thus may bear a risk premium

(4) Uncertainties that could affect demand for CCTs

(A) Natural gas prices can be quite variable, and uncertainty; may be mostly on the high side: despite EIA projections (and those of others) that gas wellhead prices will still be about $2.50/MMbtu in 2015, Frank Burke graphics in Panel 4 showed late December price spike at Henry Hub in Louisiana, and futures prices for natural gas in similar time frames, at about $4.75

(B) Capital costs may well be lower in deregulated environment: according to Bob Edmonds of Duke Power, Duke recently built a new coal unit for just over $1,000/KW in South Carolina (the Cope unit), several hundred $/KW less than present expectations: Edmonds cited cost-cutting lessons learned in Duke's recent experiences abroad

(C) Higher demand growth could spur need for new units, everything else equal: Mary Hutzler of EIA stated that an increase in demand growth from 1.5% to 2.0% from 1995 to 2015 would trigger a need for about 100 GW of new units, about half of them coal

(D) Lower prices due to deregulation could spur new electricity demand: Bob Edmonds stated that Duke projects internally that prices could drop between 5% to 30%, depending on treatment of stranded costs

II. SUGGESTED SOLUTIONS TO BRINGING PRECOMMERCIAL CCTs TO MARKETPLACE

A wide range of potential solutions was offered, some involving some government role or incentive, some involving only industry

(1) Solutions involving Government roles

(A) States currently undergoing, or looking at, the transition to deregulation are examining new ways to continue supporting "favored" technologies. These could include:

(I) a nonbypassable "wires" charge (such as implemented by California) to collect $ to be used to fund renewables, conservation, and R&D

(ii) a "portfolio standard" which would a require that sellers obtain a certain percentage of their power from favored technologies

(iii) regulatory requirements favorable to certain technologies, such as a requirement that nuclear units must be allowed to run anytime they are available

(B) Financial incentives, such as proposed by Dwain Spencer

(C) Incentives for overseas deployments of CCTs, in order to demonstrate them adequately by the time they are needed domestically

(D) Work with state regulators to develop some types of incentives

(E) Recognize in some way the fuel diversity benefits of coal

For any of these incentives, coal industry involvement above and beyond that of today was urged, because other entities might have other priorities than developing CCTs.

(2) Industry solutions

(A) Co-production (including tri-generation of electricity, heat, and chemicals) will bring price of electricity down

(B) Co-firing with “distressed fuels”

© Develop standardized plant, modular production, use cookie cutter approach to lower capital costs

(D) Coal sector should work together to produce an integrated project, just as the gas industry abroad has developed new gas fields in conjunction with identified power plant projects (parallel to mine-mouth units domestically?) To gain synergies

III. OUTLOOK FOR POSSIBLE ACTIONS

(1) Given the difficulty of obtaining financing from federal or state sources (due in part from rising budgets for social costs such as health care, according to Terri Moreland), it may be up to the private sector, possibly in conjunction with non-financial incentives such as portfolio standards and line charges, to bring CCTs to commercial fruition

(2) If there is to be government involvement, need to get private industry and different levels of government together to decide on a course of action. Right now, there appear to be many ideas, but little leadership.

(3) If there is to be government involvement, the lone remaining major opportunity is likely to be the legislation that will likely go forward in states the U.S. Congress to put electricity deregulation into practice

ENVIRONMENTAL ISSUES AFFECTING COAL AND CCTs INTO THE NEXT MILLENNIUM

Karl Hausker
Project Director and Senior Fellow
Environmental Studies
Center for Strategic and International Studies

5TH ANNUAL CLEAN COAL TECHNOLOGY CONFERENCE
TAMPA, FLORIDA
JANUARY 7-10, 1997

The panelists discussed a variety of environmental issues that affect CCT deployment, and more broadly speaking, power development in general. The issues were both international and domestic in nature. I summarize below the issues discussed and possible solutions.

I. ISSUES

International Issues

James Newman of Golder Associates described the environmental guidelines and requirements facing developers of power plants abroad. The guidelines and requirements can come from the financing entity, the host country, or the internal policy of an independent power producer (IPP). The financing entity may be a multi-national, regional, or national development bank and/or a private bank, finance company, or trading company. The guidelines or requirements may be procedural in nature (concerning environmental impact assessments, management, monitoring, public participation in planning) or operational in nature (limits on emissions or impacts on natural resources). Adherence to ISO 14000 may become an important procedural requirement.

These guidelines and requirements may pose a confusing web for a developer. However, many finance entities defer to World Bank guidelines. This can simplify the situation, but those guidelines are, themselves, in a long process of revision, creating considerable uncertainty.

Domestic Issues

Considerable uncertainty exists with respect to domestic environmental requirements as well. Brian McLean of the U.S. Environmental Protection Agency discussed current and proposed EPA regulations that affect power plants. The 1990 Clean Air Act Amendments are still being implemented in stages as directed by the legislation. For example, Phase I of the NOx and SO2 programs are underway, with Phase II coming in 2000. Other programs in the pipeline include the utility air toxics MACT and regional ozone programs. In addition, in November 1996, EPA made proposed revisions to the National Ambient Air Quality Standards for ozone and particulate matter. These standards could result in significant additional requirements for emission reductions from power plants.

Climate Change

The issue of climate change spans the domestic and international agendas. Linda Silverman of the Department of Energy discussed the latest developments in the Framework Convention on Climate Change (FCCC). The signatories to the FCCC are in the process of negotiating a binding agreement on quantified emissions limitations and reductions for the post-2000 period. This would be a major step beyond the current non-binding agreement on limiting greenhouse emissions in the year 2000 to 1990 levels (which most countries will not achieve). The U.S. position is to support an agreement that contains verifiable, medium-term emission targets that are realistic, achievable, and allow maximum flexibility. If an agreement goes into force, it would undoubtedly require limitations or reductions in fossil fuel combustion. Mark Mills of Mills, McCarthy, & Associates presented an analysis of electro-technologies that I discuss below under "SOLUTIONS".

Uncertainties Loom Large

There is little doubt that international and domestic policies will demand improved environmental performance by the electric power sector in the future. The presentations of these speakers and two Congressional staff also indicated the large uncertainties that exist over just what these future environmental requirements will be for CCT and other fossil fuel generation. Uncertainties flow from the internal decision processes of institutions such as the World Bank and EPA, the outcome of international negotiations on climate, and the impact of Congress on Administration policy proposals.

II. SOLUTIONS

My summary will highlight ideas from the panelists that could be characterized as solutions to the demand for improved environmental performance and the surrounding uncertainties. I will also offer some personal comments and observations

International Issues

Mr. Newman urged project developers to work hard to identity all the entities that might affect the environmental aspects of a power project, and determine their guidelines or requirements. Stay in close and frequent communication with these entities. Define the project early with close attention to site selection, baseline data and monitoring requirements, and public participation. I would add that, in addition, his presentation suggests that developers should press the World Bank to finalize its guidelines in order to eliminate that source of uncertainty.

Domestic Issues

Mr. McLean described the "Clean Power Initiative" under development at EPA: an effort to rationalize the current complex web of requirements and timelines, and to develop an integrated strategy for achieving the goals of the Clean Air Act with respect to the power industry. Such a strategy would employ more cap-and-trade approaches, more flexibility, and more banking. It could reduce the cost of compliance and provide more continuity to help business planning. I think there is great potential in such a strategy: it would build on the success of the SO2 trading program and is very much in the spirit of other regulatory reinvention activities underway at EPA. I would add that the more sources that EPA can include in cap and trade programs (not just utilities and IPPs), the greater the cost savings. EPA may also want to consider regional or airshed-based boundaries for trading systems if that is appropriate to the nature of the pollution problem. Finally, using an electric utility analogy, the Agency should explore "peak-shaving" approaches to some problems such as ozone. Temporary measures to address temporary peaks in pollution are under-utilized in the current system, and, in combination with permanent measures, can be cost-effective.

Climate Change

Ms. Silverman described some of the Administration's positions aimed at addressing the climate change problem in a cost-effective way. Policies should address comprehensively all greenhouse gases. Emission targets should be multi-year, rather than single-year, thus allowing nations more flexibility. Any agreement should involve a time horizon long enough to allow normal, rather than premature, turnover of capitol stock. Any agreement should allow emission trading and joint implementation. She also stressed that the U.S. opposes harmonized policies and measures because these could lead nation's away from least-cost solutions.

Mr. Mills presented analysis indicating that a multitude of technologies are emerging that substitute electricity for direct fossil fuel combustion (e.g., microwave drying for heat drying), or for another factor of production (e.g., ultrasound cleaning or chemical cleaning). In many cases, the net impact of this substitution is to decrease CO2 emissions, even if the electricity is generated by coal. I believe this phenomenon reinforces an important lesson for any effort to limit greenhouse gases: least-cost policies must recognize the complexity of the economy, and the many trade-offs that can be made. For example, a cap on electric utility emissions alone would not be as cost-effective as a cap on all emissions. The former might prevent cost-effective net reduction in emissions resulting from a increase in utility emissions coupled with a large decrease in industrial emissions made possible through electro-technologies. Similarly, a cost-effective climate policy might result in an increase in kWh production coupled with decreases in direct fossil fuel use by industry.

The Role of Education

Maura Reidy and Barbara Wainman, staff to members of the House Interior Appropriations Committee, stated that Congress is paying a lot of attention to the issues raised here. They also stressed that Congressional members need plenty of education, especially given recent turnover and the influx of relatively young members. This is consistent with the comments from many attending the conference on the importance of education in general.

CCT DEPLOYMENT: FROM TODAY INTO THE NEXT MILLENNIUM

ISSUE 4 RAPPORTEUR REPORT

ALL SECTORS REPRESENTED: Utility, Industrial, Fuel Supplier, Technology Supplier, State Government.

ALL EXPRESSED CCT FACES MANY UNCERTAINTIES: Barriers, Hurdles, Problems

1. Electric Deregulation -	Postpone Capacity Additions (49.6%CF)
	Soft Market (load growth in US lower)
	Need for Smaller Generation
2. Capital Expense-	Higher
	Seen as Demonstration vs. Standardization
3.Competition-	Gas Price Low
	Natural Gas Generation Technology Advancing (Eff. 50-60%)
	Known Natural Gas Supplies Increasing (30% in last Decade)
	Global Competition for Industry

4. Environmental-	Can go to far (CCT not enough)
	Can Discourage Retrofitting (Updating may Trigger NSPS)
	Uncertainty of Regs. Even 2 & 3 Years From Now (NOx 60% today 80% tomorrow)
5. Government Dollars-	Fewer Federal & State (30% Reduction of state funds in 2 years)
6. CCT Energy Awareness-	Stigma of Coal in General

Public attitudes toward coal remind me of a resent political survey that ask Americans on the Street, “What is the bigger threat to our Democracy - Ignorance or Apathy?” The overwhelming response was, “I don’t know and I don’t care!”

First, for CCT to be excepted (like natural gas) it must be KNOWN!

Second, We must not be APATHETIC about the promotion of our product! The positive societal changes CCT can bring to the world are dramatic.

FOR EACH PROBLEM THERE IS A SOLUTION!

1. Electric Deregulation-	Legislation may Include Environmental Requirements that promote Retrofit Tech.
	Legislation may carry provision to encourage use of domestic resources and reliability provisions
2. Capital Expense-	CCT no longer Demonstration (TEXACO) Commercialization/Standardization Facilities

	Financial Commitment is there! (IGCC Texaco, CFBC Phillips Coal Miss.) JOINT VENTURE PARTNERS RISK MANAGEMENT
3. Competition-	Increased generation efficiencies
	Standardizing the fuel - coal blending
	Natural gas prices are unstable
	O & M expense cut with “smart” operating systems
	Duel-Fuel generating capacity
	Economies of Scale (multiple products & multiple feedstocks)
	Integration with other processes.
4. Environmental-	Retrofit may grow if standards not too sever
	Foreign Opportunities
5. Government Dollars-	Expedited Permitting
	Tax Incentives Local
	Targeted Export Assistance
	State-Federal Coordination
6. CCT Energy Awareness-	SSEB (regional groups)
	1998 25th Anniversary of Oil Embargo

We can as Robert Bessette quoted from Jesse Jackson “like a honey bee have the sense to repollinate the flower”. With a 7.5 Billion dollar investment I don’t believe we will let this flower die!

ACTIONS

1. Develop comprehensive document listing State & Local incentives. (Taxes, Land, Permitting, etc.)

2. International conference on IGCC (explore integration with other processes, products, and feedstocks)

3. Fund groups like SSEB to promote CCT awareness

4. Start a program to tour key federal and state regulators through CCT sites

5. Lobby Congress for increased domestic resource use and dual-fuel standard for electric system reliability.

I will leave you with one final quote. It has to do with Capital. We have discussed capital expense , capital cost, capital outlays.

THOMAS EDISON SAYS :

> “TIME IS REALLY THE ONLY CAPITAL THAT ANY HUMAN BEING HAS AND THE ONLY THING HE CAN’T AFFORD TO LOSE.”

I believe our time spent at this conference was not capital lost but capital well invested. We must go foreword now and change the stumbling blocks into stepping stones.

Featured Speaker

The Honorable Ralph Regula
Chairman
Subcommittee on Appropriations
U.S. House of Representatives

Thank you.

I like to be out with the audience and I want to interact with you because we are teammates. You're not going to get another brilliant technology speech, and so I can relax on that one. But I think you've set the stage on what we need to do and that is education. You're going to forget 99% of what I say, but I have a couple of things that I hope you remember.

First of all, I want to say you're my heros, because I think Clean Coal Technology is the future. We are sitting in this country and many other countries on tens of decades of supply. We fought a war over oil, you can talk about desert storm anyway you want to, but we were there because of oil and if it were no oil, we would not have been there, but neither would be **Sedam Husan.** So that's what it's about and I'm glad we have people from other countries.

I'm on the North Atlantic Assembly as one of the delegates and now that we're talking about environmental issues (we use to talk about how we could kill each other, today we're talking about how we can create economic growth and jobs around the world) at our last meeting and I'm on the committee. I looked up at the dias where they have the flags of the countries. There normally would be 16 flags (16 NEDO countries). This year there were 33 flags because 17 other countries were participating in these NEDO discussions and talking about environmental issues and jobs. And that's where it is in the future and that's why clean coal technology is vital not only in the United States, but around the world. And I'm glad that we have people representing these other countries.

What I hope you remember is that each of you needs to be a lobbyist and each of you need to educate members' of congress or others. I met with a delegation from the Ukraine who was visiting probably the most modern steel mill in the world. That's in my district, the Temkin Company. And they were the managements of steel plants of the Ukraine and the reason they were in the United States is because they were getting pressures back home to clean up the steel industry (that deal with environmental questions). And they were here in the United States visiting steel companies to find out how.

When I visited with them, I said that's fine but you also need to interact with your legislatures and I said that after all they're part of the team. And that's so important to all of you to get on a one-to-one basis with members of congress, governors, state legislators because we have critical issues coming up. It does make a difference and what you need to talk about is how it affects jobs.

Bill Clinton got reelected President because the economy is good, because the pocketbook issue, that's what people understand. The best job of lobbying I've every seen was done by the Chrysler Corporation. If you remember back when they were almost bankrupt, and we had to bail them out, we had to co-sign their note in effect (we the United States government). They came into my office, they had documented down to the last screw and bolt and nut that was made in the 16th District of Ohio, because we don't have any auto industry. They had documented how many people were working in Chrysler agencies fixing cars and it turned out that the 16th District owes 50 million dollars worth of activity, all affecting jobs. And believe it or not they, as you well know, they got the bail out. I didn't vote for it because I don't have to think that it was an appropriate way for government to be involved. But never the lest it saved Chrysler and today I just read in Forbes magazine coming down here that, I think they were nominated as the number one company of the year by the 400 CEO's that were polled by Forbes.

So it illustrates what you need to talk about are jobs, and the two big issues that will be of interest to all of you this year and next year and probably a couple of years down the road, in the case of deregulation of electricity. It's coming, we deregulated trucking, shipping, telecommunications, you're next in line. And I tell my audiences back home, I said now at 5:30 when you sit down to dinner the telephone rings and somebody wants to sell you long distance service MCI, Sprint, you name it.

You get ready, in a couple of years they'll want to sell you electricity. It may be Pacific Gas, Tampa Electric, I hope I get a call from Bonneville because they've got a great rate. The government's taking care of that one. But I don't think I'll get a call from REA, rural electrification. I'll get a call from them not to sell me electricity but to tell me that deregulation is not a great idea. So all I'm saying is, get in touch and don't just say I'm _____, tell people who represent you in the state legislature, in the congress and the governors how this will affect jobs, how it will affect economic growth, how it will affect the competitiveness. Our governor in Ohio likes to say "the rust is off the belt" because Ohio was for many years the called "rust belt." It's not the "rust belt" anymore. I mean people understand that this deregulation issue is very complex to say the lest. You've got the problem of the stranded cost, you've got the problem of the REAs, you've got the problem of the Bonneville, how do they fit in TVA? I can see enormous problems, but some how we're going to work it out. And you therefore ought to be part of the process and I hope if you forget everything I say that in the few minutes I have you'll remember that and take some responsibility for it.

And of course the second issue this time is going to be the clean air question. They're going to propose (I think it's scheduled for June 28th) a proposal that changes clean air regulations. One of the things that we did in this session in the Small Business Recovery Act is put in a probation that a proposal and change of regulations require an economic impact statement. Meaning that when EPA proposes these, they've also got to say how's it going to impact on the economy, what's its going to cost in jobs, what's it going to add to the cost of electricity, of gasoline, all kinds of other things. Because regulations do have that kind of impact. What's it going to do to our competitive position in the world today, which of course relates backs to jobs. It relates back to taxes for school systems, United Way contributions and on and on and on. It affects the quality of life all across the board, and therefore it's important that you have input to us.

You know the 435 members of the house and 100 members of the senate and legislatures and the governors. We got it coming at us from all directions. I vote with a card, it's the world's greatest credit card because I can vote with this card and my grandchildren are going to get the bill. You put this card in a slot (that's my voting card I've used it six or seven hundred times last year), and there are only two buttons. One that's says present (if you want to a cop out), otherwise it's yes or no. **And when I vote, that's a wide reaching in ramifications.**

The point is that I have to use that on a merit of subjects. Therefore it's important that I be educated. And the way that happens is that people that I know in my district, that are involved in the power industry or whatever, talk with me about what kind of impact deregulation will have. What kinds of impact Clean Air Act Amendments will have. And we're going to get the economic statement. That's a big improvement of the regulation process. But also we're going to add 60 days in which we have to decide weather or not to try to modify these proposals or block them. Very important decision and we need as much information as possibly. Particularly because those who are on the other side for whatever reason are going to be very aggressive, very ___ in their position and therefore it's important that all of you be involved in that process and I think those will be the two big items that will affect your industry in 1997.

I think in the deregulation industry it will go on to 1998. There will be others that affect you. I thought one of the most significant pieces of testimony I heard last year was Alan Greenspan. Alan Greenspan, Chairman of the Federal Reserve, obviously sets monetary policy for the United States. By the way he's going to get married. If you've read the papers than you can tell Alan is not one to act quickly. He's been going with Andrea Mitchell for 12 years but he's finally taking the plunge. Maybe that will moderate interest rates, I don't know.

Alan Greenspan said (I'd quote him almost verbatim) to the budget committee members "if you balance the budget for the next seven years" I think this was in 1995. "If you will do that, your children, your grandchildren will have a better standard of living than you do." Now that's an enormous promise and a very important one. Why did he say that? Because interest rates will come down, interest rates come down, you and your industries can expand. My ______ company in Republic Steel, Hoover, Rubbermaid and Smuckers can expand produce more jobs, we're back to J-O-B-S, and be more competitive in the world marketplace. Because interest is a very significant part of the process of doing business. And so our mission in the legislative side is to help make that happen. Therefore I think the number one issue in 1997 will be the budget.

I was in the presidents office about a month ago, he signed a bill that I was involved with and a number of other members. After he signed the bill the press was out, the TV cameras and the first question from the presses. "Mr. Clinton, what is your number one issue for 1997." And he immediately responded "Balancing the Budget." That's good news, now how we do it becomes a different matter. And where the priorities end up being allocated, but I think this is very important. It's important not only in the United States but around the world.

I noticed that some of the countries like Sweden and Norway which traditionally has socialistic governments are beginning to discover that the cost of all these programs is becoming an excessive burden and makes them lest competitively in the marketplace. So the number one issue next year is going to be, I think the budget issue, another issue for 1997 will be taxes. Bill Archer is Chairman of the Ways That Means. He went down and had a one-on-one. No staff present, just the two of them talking about tax reform and he came back some what optimistic. The president in the campaign promised some changes like making your home sale tax free, allowing you to deduct the cost of sending your children to college. But in order to get those, which he obviously will propose, we the Republicans will probably say how about some capital gains relief. How much I don't know? How about some individual relief. So all I'm saying is this whole tax issue I think will be discussed at great length in the 1997 session.

We of course have the proposal for the "flap tax" that Steve Forbes put out there. It has its fans including Dick Army, the number two republican in the house and then Bill Archer whose Chairman of the Tax Writing Commission would like to go to a National Sales Tax or something like a Value Added tax. So its going to be a lot discussion but again it will affect your businesses considerably. And therefore it's important again that you get involved. I'm not going to ask a show of hands, but if any of you have do not personally have a contact with both your congressman, senator and your state legislature, you're missing the boat. I don't mean sending a check for their campaign, I mean getting to know them. Call them up, go to a meeting if necessary and button whole them. They button whole me all over the place.

Best lobbying job I ever had was when I was in state senate we were going to change the driving age. The AAA was for it, the state patrol was for it, the insurance industry was for it. Ohio 16 we're going to raise it to 18. Well my two boys who were about 15 and 13 said dad we want to have a little meeting with you, when I got home. They said dad how are you going to vote on the driving change, the age? Well I said everybody is for it. They said if you vote for it, you can mow the lawn yourself. And that got my attention.

But all I'm saying is that you got to get to know, you got to contact people. You bring to us this process called education because again we got so many difference things we have to deal with every day and therefore it becomes important and we have this base of knowledge when we have to go in and put this card in the slot. And of course in the committee hearings it's not just the card in the slot. Its the flow chamber. But it's the committee hearing's, I voted committees that's not normally public awareness on committee votes and yet those are the ones that have a great impact how you put that bill together. The congress committee has to deal with the deregulation issue and in the committee once a bill gets to the floor its tough to change. You can offer _______________, but the real work is done in the committees, that's where the house is built. And you might put a little extra _____ on the porch, around the house by buying large. You got to do it the committees.

So beyond talking to members, you should talk to members that are on the congress committee in the case of deregulation, you should talk to a member on the Waste and Means committee in the case of taxes.

Now another area I think would be important in 1997 is Education. We've passed the Welfare Reform Bill. We're saying that in two years people are off of welfare. Well we're a compassionate society we're not going to shove people out on the street with their three or four kids, that single mother, it's just not going to happen. That means of course that we've got a two-year window to ensure that individuals get some education, some skills and we need to work on that. I think that's a big issue and it's a big social problem that we all need to be involved with. Your companies ought to be looking at ways in which you may be able to offer some employment opportunities to these people. Because welfare is changing and that means that these people have to have jobs if they're going to go off of that. I think that in terms of entitlement, that'll be another tough issue. I don't have time to get into that but I would say overall what we're trying to do (believe it or not) in the congress is manage government better.

I'm a fan of Edward Demning. Japan had to teach us that Edward Demning had the right idea, he was not a profit in his own country. He went to Japan and they learned well from him and then he finally came back here. We got to do that in government, we can't balance that budget in the way that Alan Greenspan is talking about unless we manage better and we have taken some steps. I'm on the Appropriations Committee, we cut 53 billion dollars out of the budget over the last two years. Now that's 53 billion dollars that we're not going to send to my grandchildren in the way of a bill. Not only the 53 billion dollars but that compound interest that goes on and on and on.

The interest on just the national debt now is one of the biggest items in the budget and its growing, so we need to address it and it can be done. The idea was some very popular thing's parks, forest, recreation, Smithsonian all these things and yet we've cut the employment levels in agencies. Just in our subcommittee 15%, and we've cut the budget 9½%. And it can be done, just as you are. Because of competition going to have to continue to look at that that will be one of the phases of deregulation you'll no longer have a Public Utility's Commission standing guard there and telling you here's what your guarantee profit will be for the next period of time. And so you're going to be looking at ways on how to be more competitive and I hope that the use of coal will be one of them. I think it will be and that's why the clean coal technology becomes extremely important.

Housekeeping issues, at lest for the time being the focus will move to the senate in the congress. In the last two years the house has tended to be replaced where the initiative came out of but I see that changing, partly because the speakers have some difficulties. From watching the news, simply because the senate picked up a seat and Trent Lawd is a new person. Trent is going to be a very effective leader. He will be able to communicate extremely well with the President. I know Trent, he and I came to congress together. A very able-bodied individual. And I think that because the President is going to be interested in his place in history he certainly is not going to run for any more offices, I don't think. And because we the Republicans want to demonstrate that we know how to govern, we discovered that when we shut government down that it didn't do any good for us politically, we're not going to do that again. But we are going to try to work with the President to manage this government better to accomplish his goal which is a balanced budget and our goal making a different way and they'll be some give and take. That it can happen which we demonstrated in the last six months of 1996, we worked out a number of very significant issues, a budget got signed, we had welfare reform, emigration reforms, some regulatory reform a number of things. Because we had a little give and take. What the American people wants and people all of the world want. They want the politicians to work in ways that will be beneficial to the public and not worry so much about partisanship. And I think that could well be the hallmark of the 1997 session as we deal with some of these tough issues. But you're part of the team too and you have to have your input not only in terms of your professional association but as individuals and therefore I come full circle and say get involved, get to know the people that represent you give them your input so that we can make good judgements, so that we can make policy that will be significant and worthwhile value for a long term.

Deregulation, that's going to have an impact for decades. And therefore we need to do it right. On the telecommunications bill we sent it down and the President vetoed it (it came back). I didn't vote for it the first time. I didn't like all the characteristics of it. We finally got something, it may not be perfect, but it's better than when it went into the shoot to start with. And that's all a part of the legislative process.

I think lastly, we're going to an effort to get broke, we're at about 2.3%, 2.5% annual. We need to do things to get it up to 4%. Because that will help to solve the entitlement problem, that will help to solve the deficit problem, that will help to solve the problem of being competitive in the world marketplace. So many things could blow of a ________ ________ out getting this country in a 4% growth pattern which it use to be. It will of course come back to jobs, when you have 4% growth you have jobs available. You have a high level of employment. We can make jobs for those people who are going to be pushed off of welfare but in turn have to do their share by getting a skill. We need to give them the opportunity.

Right now we got 165 post high school programs, I'm not talking about college, I'm talking about skill programs, some big ones, some little ones. We want to consolidate those into three or four really good programs that will help these people get skills. But again you need to be involved in the mix in local community so that the skills given, there's a market for them because it'll be nothing worse than to have somebody to spend six months acquiring a skill and there's no job that fits that skill. And to often we have not tried to coordinate it.

Well again you're my heros because you're working on a program, we had a real struggle to get the clean coal program. What I like about it is, its going to reduce our dependency on oil long term. We required a 50/50 match in terms of the private sector and that's become a pattern on a lot of things in government. I think clean coal is one of the first major policy issues where we did that requirement of having 50% out of private sector. As it's worked out. Its really 60/40, because it's a bidding process 60% private, 40% government. It's been very successfully, we're going to do our children and grandchildren a great favor if we can expand the use of coal. We're now at 56% of the power produced in this country from coal generation. I think it would be a shame to give them a legacy of dependency on imported petroleum because we've used it to produce electricity when coal can do it so well, while at the same time taking care of the commission requirements to meet the standards.

Let me stop there and answer any questions.

Recent Experience with the CQE™

Clark D. Harrison and David B. Kehoe, CQ Inc.
David C. O'Connor, Electric Power Research Institute
G. Scott Stallard, Black & Veatch

Increasing public awareness about the health of the global environment, tightening emissions regulations, growing competition among power producers, and advances in power generation technology are transforming the business of power generation worldwide. This transformation has further complicated fuel purchase decisions that profoundly affect the cost of electricity.

CQE (the Coal Quality Expert) is a software tool that brings a new level of sophistication to fuel decisions by seamlessly integrating the system-wide effects of fuel purchase decisions on power plant performance, emissions, and power generation costs.

The result of a $21.7 million U.S. Clean Coal Technology project sponsored by the Department of Energy and the Electric Power Research Institute, CQE offers unparalleled advancements in technical capability, flexibility, and integration.

The CQE technology, which addresses fuel quality from the coal mine to the busbar and the stack, is an integration and improvement of predecessor software tools including:

- EPRI's Coal Quality Information System
- EPRI's Coal Cleaning Cost Model
- EPRI's Coal Quality Impact Model
- EPRI and DOE models to predict slagging and fouling

CQE can be used as a stand-alone workstation or as a network application for utilities, coal producers, and equipment manufacturers to perform detailed analyses of the impacts of coal quality, capital improvements, operational changes, and/or environmental compliance alternatives on power plant emissions, performance and production costs. It can be used as a comprehensive, precise and organized methodology for systematically evaluating all such impacts or it may be used in pieces with some default data to perform more strategic or comparative studies.

Overview of the Project

The CQE project was conceived by EPRI to integrate the results and products of several on-going R&D projects into computer software that would become a worldwide standard for addressing fuel-related issues in the power industry. EPRI and DOE sponsored numerous coal quality R&D projects in the late 1970s and early 1980s to carefully examine and document the answers to questions that need to be addressed before a utility can be certain that it is operating its power plants within emissions limitations at the lowest possible cost:

- What are the economics of burning a prospective coal?

- How would the delivered price of coal change if the supplier cleans or blends the coal(s) to produce a product with quality characteristics different than the coal currently delivered to the power station?

- To what degree can the quality of the coal currently delivered to the power station be changed?

- What power plant equipment and systems are most affected or limited by coal quality?

- What are the trade-offs between increased capital spending at the power stations and increased cost of fuel for higher quality?

- How will alternative emissions control strategies affect the production cost of electricity at a specific unit?

- Are the slagging and fouling consequences of burning a prospective coal affordable?

Coal producers and equipment manufacturers must also address these questions from a different perspective to assess the potential value of alternative products and services for utilities. For example, a coal producer contemplating changes to an existing cleaning plant or a manufacturer trying to sell replacement parts for coal pulverizers would both be interested in using a model that could accurately determine pulverizer performance, power consumption and maintenance costs for potential utility customers to provide a fuel that matched plant/unit capabilities and goals. CQE was conceived as the tool to serve the needs of these prospective users as well as the utilities that were already using CQIM and related EPRI and DOE software.

Background and History of the Project

In the mid 1970s, EPRI initiated its effort to understand the linkage between coal quality and power plant performance, emissions, and economics. Initial studies focused on the potential savings in capital cost of new coal-fired power stations that would result from the use of cleaner coal (1). To quantify the costs of producing cleaner coals and to evaluate the potential for physical coal cleaning to improve the quality of U.S. coals for power generation, EPRI initiated a coal cleanability characterization program at the Coal Cleaning Test Facility (CCTF) which it constructed in 1980-81. The facility's mission also included the demonstration of emerging coal cleaning technologies to accelerate their commercial deployment.

In 1982 EPRI started a parallel effort to build a state-of-the-art computer model that would predict power plant performance, production costs, and emissions based on laboratory and bench-scale coal quality measurements. The initial effort was focused on defining the specifications for the model and assembling the proven methodologies for predicting coal quality impacts on various power plant systems and components. A complementary effort to perform laboratory, bench-scale, and pilot-scale coal quality analyses was also initiated by EPRI in the mid 1980s, and since the Coal Cleaning Test Facility became the source for most of the combustion test samples, its name was changed to the Coal Quality Development Center (CQDC).

When the DOE Program Opportunity Notice for the Clean Coal Technology Program was issued on February 17, 1986, Combustion Engineering Inc. on behalf of EPRI prepared a proposal for the development of the Coal Quality Advisor that was later renamed the Coal Quality Expert, or CQE. The project proposed by Combustion Engineering included coal cleanability characterization of selected additional U.S. coals, laboratory, bench-scale, and pilot-scale combustion testing of representative samples of the run-of-mine and clean coal; full-scale power plant testing of those coals to verify coal quality effects; and the development of the software tool that would replace pilot-scale and full-scale demonstrations in the future. The proposal by Combustion Engineering was not selected from the initial awards for Round 1 of the Clean Coal Technology Program, so EPRI proceeded with some aspects of the proposed project in the meantime.

By the time the Combustion Engineering proposal was selected for negotiations in 1988, EPRI had completed the initial version of the Coal Quality Impact Model (CQIM™) and initiated some pilot-scale and commercial power plant testing programs. The result of these efforts and the previous work done by EPRI at the CQDC (and CCTF) were contributed by EPRI to the CQE project and the scope of the project was redefined to incorporate the testing and software development work necessary to complete a rigorous and robust model.

During the course of the project from May 1990 through mid-1996, computer technology and the methodology available to measure and predict coal quality continued to advance, so CQE was developed to incorporate as many of these advancements as possible and to maintain the flexibility to incorporate new features or update existing methodologies economically in the future.

Project Organization

As EPRI's contractor with responsibility for bench-scale and pilot-scale testing to correlate coal quality characteristics to power plant performance, Combustion

Engineering (now ABB CE) submitted the proposal for the CQE project to DOE. While the DOE CCT1 project award decisions were being made, EPRI engaged Black & Veatch to develop the original Coal Quality Impact Model software and Electric Power Technologies to conduct full-scale power plant coal quality impact tests. In addition, coal cleanability characterization efforts continued at the CQDC and EPRI developed plans to establish the CQDC as EPRI's wholly-owned subsidiary.

When DOE selected the CQE project for negotiation, EPRI and Combustion Engineering felt that it was appropriate for CQ Inc., EPRI's subsidiary, to integrate and manage the efforts of the project team as shown on the project organization chart, Figure 1-1.

Under this organization, both CQ Inc. and Combustion Engineering executed the Cooperative Agreement with DOE and both contractors became co-prime contractors for the project with project management and administrative duties being delegated to CQ Inc. Consequently, the project was organized so that each participating organization other than EPRI and DOE would be subcontractors to CQ Inc.

As new computer technologies developed during the project and as the definition of CQE became more defined, some logical changes were made in the project organization. All software coding responsibilities were centralized at Black & Veatch. When a decision was made to exclude the Fireside Troubleshooting Guideline from the CQE code, Karta Technologies' role on the project ended, and when CQ Inc. required assistance with the design of the coal cleaning and blending models, Decision Focus was added to the project team as another subcontractor. The roles of the University of North Dakota Energy and Environmental Research Center (UNDEERC) and PSI Technology were also expanded to include the delivery of fouling and slagging prediction methodology to Black & Veatch.

In recognition of the value of CQE to their customers and to continue their support of EPRI's and DOE's coal quality R&D programs, ABB CE willingly reduced its scope and budget on the project to provide funding for more robust slagging and fouling models for CQE. ABB CE led the efforts with UNDEERC and PSI Technology that distinguish CQE from other software tools that rely on empirical indices to indicate potential slagging and fouling problems.

In addition to its role as co-sponsor, EPRI also provided technical leadership to the project for the pilot-scale and full-scale power plant testing programs and directly managed the software development tasks. EPRI's CQIM User's Group provided a sounding board for CQE development ideas and served as a project advisory committee. Moreover, five members of the user's group served as beta test users of the prototype software.

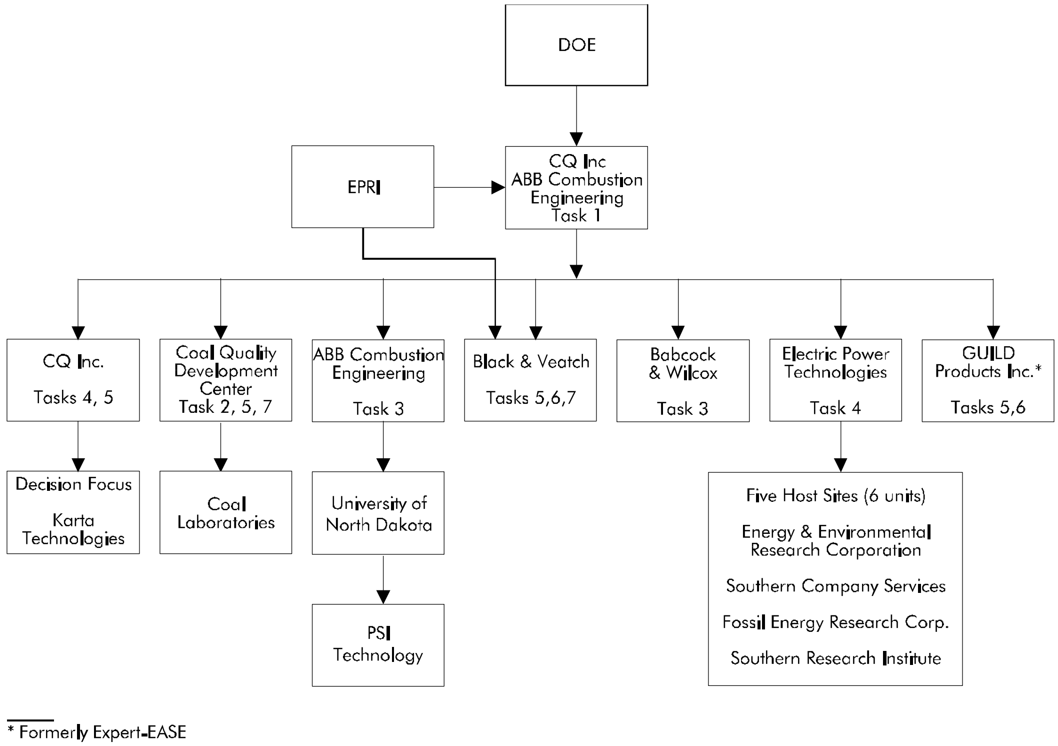


Figure 1-1
Project Organization Chart

Project Description

Although the project mission was to deliver a software tool, the scope of the project included numerous supporting tasks to collect and analyze data to form the basis for CQE algorithms, methodologies and submodels and to verify the accuracy and integrity of the CQE software at the conclusion of the project. These responsibilities are described in Table 1-1.

At the conclusion of each testing program, the responsible contractor prepared a detailed report and data summary for the host utility to use in addressing near-term problems and objectives and to aid the other CQE project contractors in completing their assigned tasks.

Table 1-1
CQE Organizational Responsibility Assignment

Test Sites	ABB/CE and PSIT	B&W	B&V	CQ Inc.	UNDEERC	EPT	GUILD
Northeastern	5 DTFS 5 FPTF	NA	need FT/PT/BT data	2 CCC	4 DTFS 5 SEM	3 FT	NA
Watson	2 DTFS 2 FPTF	NA	need FT/PT/BT data	2 CCC	2 DTFS 2 SEM	2 FT	NA
King	NA	2 SBS	need FT/PT/BT data	5 CCC	2 SEM	2 FT	NA
Gaston	1 DTFS 1 FPTF	NA	need FT/PT/BT data	2 CCC	NA	2 FT	NA
Brayton Point	NA	NA	need FT data	NA	NA	2 FT	NA
Brayton Point	NA	NA	need FT data	NA	NA	2 FT	NA
Other CQE Work	commercial applications and slagging models	NA	CQE software developer, CQIM enhancements, ARA	Coal Cleaning Cost Model, CQIS enhancements, select CQE test sites	ash deposition data & fouling models	Fireside Testing Guidelines	develop CQE shell specs

CCC--Coal Cleanability Characterization
SBS--Small Boiler Simulator (Pilot Test)
BT--Bench Test
DTFS--Drop Tube Furnace System
FT--Field Test
PT--Pilot Test
FPTF--Fireside Performance Test Facility (Pilot Test)
SEM--Scanning Electron Microscopy

The highlights of the project are shown in Table 1-2.

The following U.S. electric utilities cofunded the project and participated in the field testing and software development/testing efforts.

Alabama Power Company
Wilsonville, AL

Duquesne Light Company
Pittsburgh, PA

Mississippi Power Company
Gulfport, MS

New England Power Company
Somerset, MA

Northern States Power
Oak Park, MN

Public Service Company of Oklahoma
Oologah, OK

Southern Company Services
Birmingham, AL

Table 1-2
Project Accomplishments

Accomplishment	Date
DOE awarded Cooperative Agreement	5/3/90
First of six field tests started	7/90
Pilot and bench-scale testing started	11/90
CQE specifications completed	2/15/92
Pilot and bench-scale testing completed	6/92
Acid Rain Advisor--first commercial product--released and copy sold	3/93
Completion of all six field tests	4/93
CQ Inc. and B&V signed CQE commercialization agreements	10/13/93
Conceptual design of the general Interactive Output Utility completed	8/94
Partially functional CQE beta version successfully tested	12/94
CQE alpha-version completed	3/31/95
CQE beta version completed and released for testing	6/95
Beta testing complete	11/30/95
CQE revised and issued on CD ROM	12/95
CQE Release 1.1 beta issued	6/7/96
Final Report	8/96
CQE Release 1.0	12/96

CQE builds on existing correlations from worldwide R&D on the impacts of coal quality for specific parts of the total power generation system. CQE features EPRI's CQIM as the calculational foundation for determining the impacts of different coals on plant performance and costs, and EPRI's Coal Quality Information System (CQIS™) provides a national database of coal quality information.

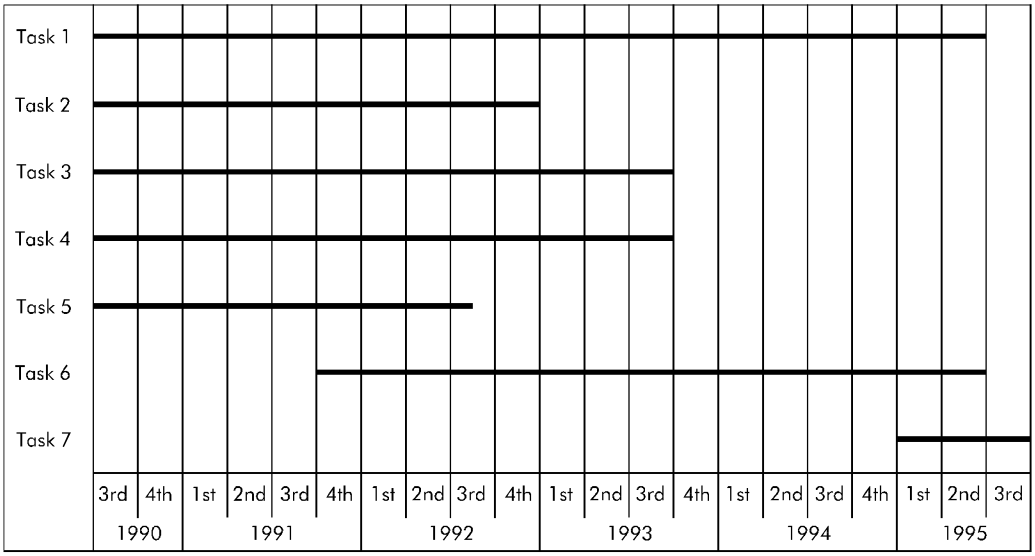
CQE combines the expertise from these established models--or the models themselves--into a single, personal computer-based tool. The electronic consultations that occur transparently between CQE's models let users address all aspects of fuel issues and their corresponding impacts on power generation systems.

This groundwork of established models is complemented by new and enhanced models derived from bench-, pilot-, and full scale test programs. These test programs, which allow coal-related effects to be distinguished from operational or design impacts, are among the most extensive of their kind ever conducted to relate power plant performance and emissions to coal quality.

Project Schedule

The original 42-month project actually spanned 64 months because the required "off-the-shelf" software for OS/2 was late.

The extended duration of the project required increased funding from EPRI and DOE, but it ensured that CQE was adequately planned and that CQE's underlying computer software was adequately proven. The project schedule is given in Figure 1-2.



Task 1 - Project Management
Task 2 - Coal Cleanability Characterization
Task 3 - Pilot-Scale Combustion Testing
Task 4 - Utility Boiler Field Testing
Task 5 - CQIM Completion & Development of CQE Specifications
Task 6 - CQE Development
Task 7 - CQE Workstation Testing and Validation

Figure 1-2
Project Schedule

Objectives of the Project

The work falls under DOE's Clean Coal Technology Program category of "Advanced Coal Cleaning." The 64-month project provides the utility industry with a PC software program to confidently and inexpensively evaluate the potential for coal cleaning, blending, and switching options to reduce emissions while producing the lowest cost electricity. Specifically, this project was designed to:

- Enhance the existing Coal Quality Information System (CQIS) database and Coal Quality Impact Model (CQIM) to allow confident assessment of the effects of cleaning on specific boiler cost and performance.

- Develop and validate a methodology, Coal Quality Expert (CQE), which allows accurate and detailed predictions of coal quality impacts on total power plant operating cost and performance.

Significance of the Project

Originally, coal cleaning technologies were used only to remove ash-forming mineral matter. After passage of the 1970 Clean Air Act, coal cleaning processes were applied to a second purpose--sulfur reduction--accomplished primarily by removing the sulfur-bearing mineral pyrite. A great deal of geochemical information concerning the modes of occurrence of pyrite in coal was gathered and used to develop new methods of sulfur removal and to enhance existing methods. Today, coal cleaning plays a larger role in controlling SO_2 emissions than all post combustion control systems combined. It has led to reduced SO_2 emissions while U.S. coal use by utilities has increased steadily since 1970 (see Figures 1-3 and 1-4).

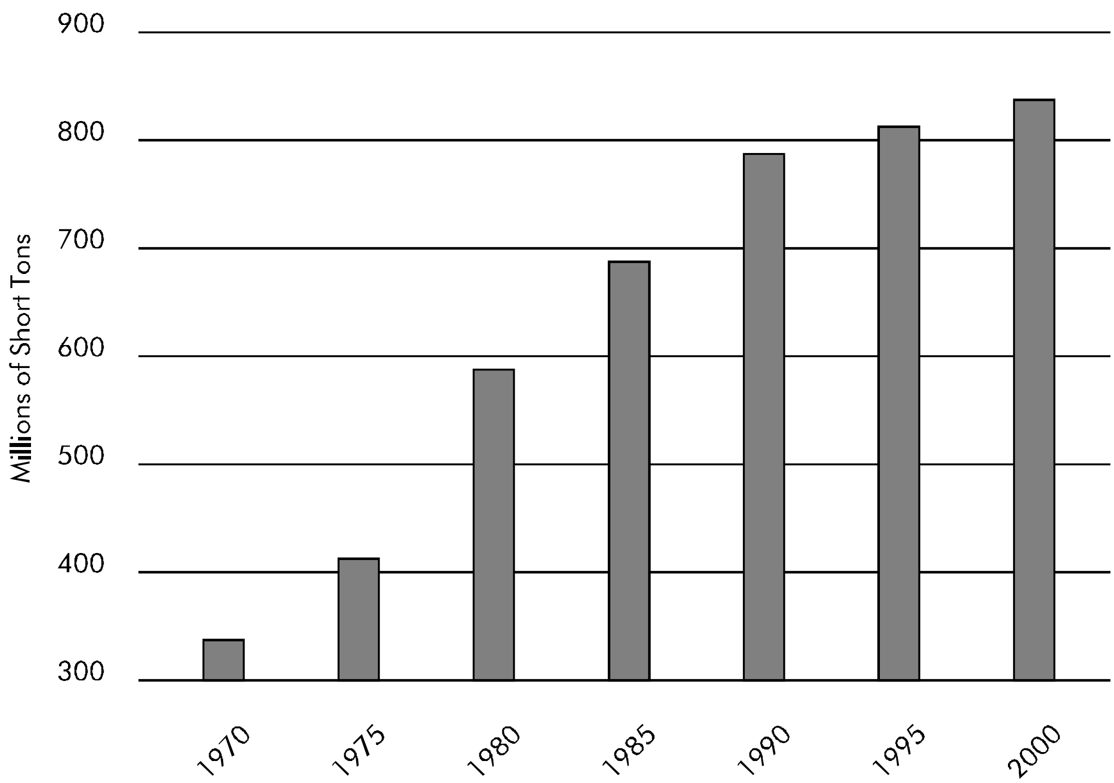


Figure 1-3
U.S. Utility Coal Use

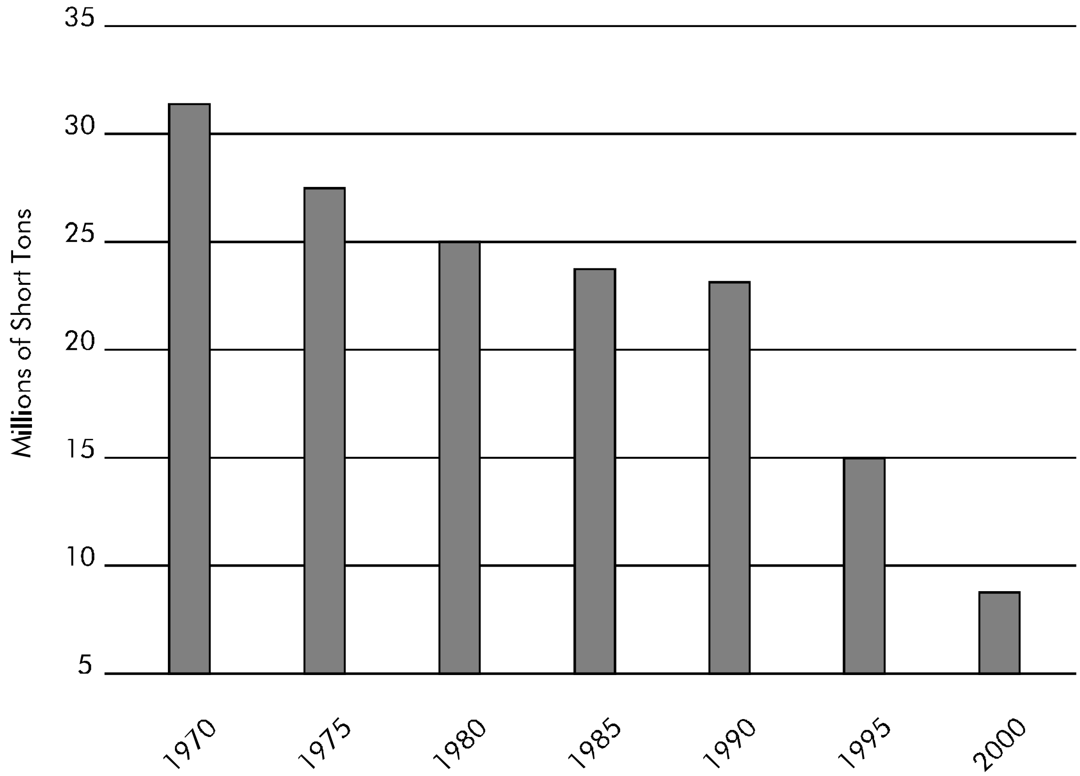


Figure 1-4
Total U.S. SO_2 Emissions

Coal cleaning has been commercially demonstrated as a means of reducing sulfur concentrations in some types of coal to levels which allow firing in boilers to conform to environmental standards without using scrubbers. In addition, coal cleaning reduces the concentrations of mineral impurities which may result in significant improvements in boiler performance, reduced maintenance, and increased availability. Figures 1-5 and 1-6 illustrate trade-offs which dictate the feasibility of coal cleaning. Sulfur emissions produced when burning a coal generally decrease with increased levels of cleaning. Fuel costs, however, increase with increased levels of cleaning (Figure 1-5). Another consideration is that performance benefits can increase with increased cleaning for existing units and higher quality fuel reduces new unit capital costs (Figure 1-6).

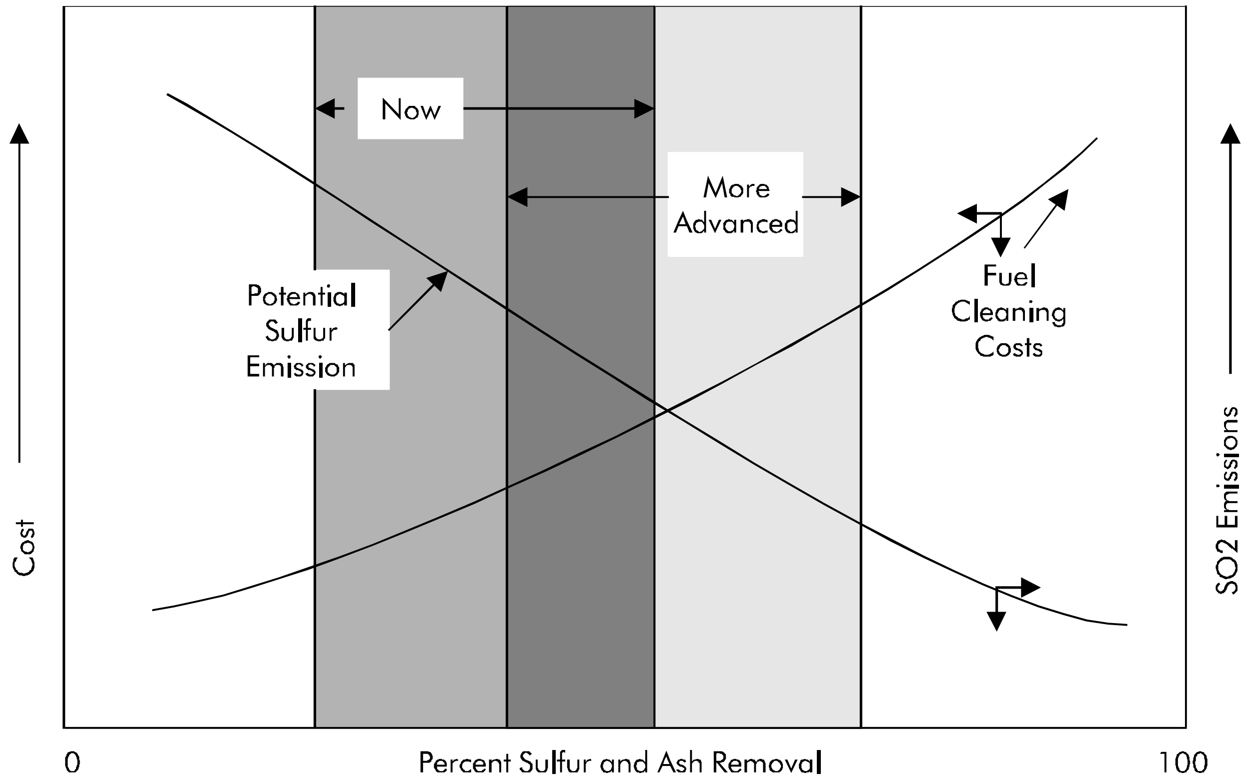


Figure 1-5
The Relationship Between Sulfur Emissions and Fuel Costs

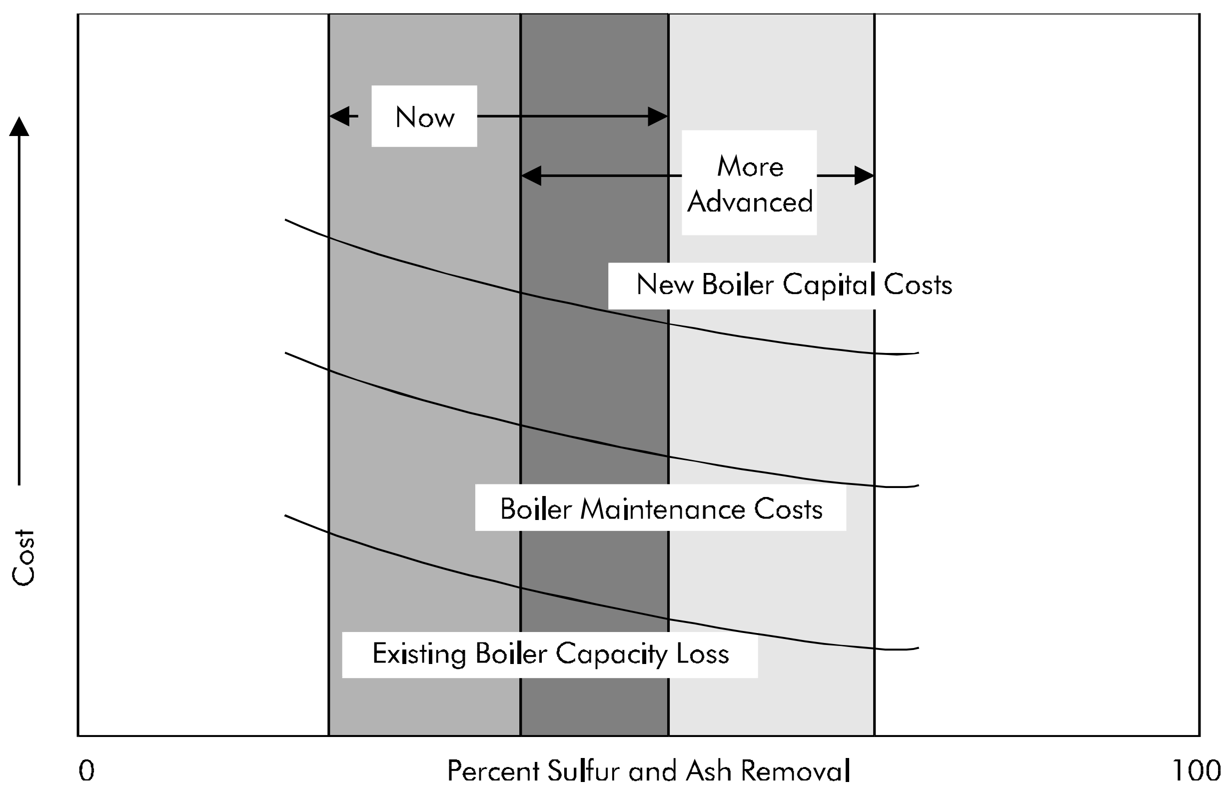


Figure 1-6

Coal Cleaning to Reduce Power Production Cost

Studies have indicated significant economic benefits due to coal cleaning (2). However, to accurately and completely assess the commercial viability of cleaning a particular coal, detailed large-scale combustion testing is necessary. Quantification of performance savings is necessary to compare the economic benefits obtainable through coal cleaning with the costs of other techniques for emission control. Industry currently does not have the capability to reliably predict the performance of cleaned coals without extensive studies. The relationship between level of confidence and testing coals is illustrated in Figure 1-7. Since many of today's bench-scale coal performance indices rely on empirical correlations, extrapolation of these indices to fuels not represented by the specific database used for correlation can be misleading. The need for quick, inexpensive tests that can be reliably used to assess the commercial impacts of coal cleaning is vital to implement clean coal technology. One of the major goals of the program was to develop and demonstrate simple techniques (bench-scale fuel properties and predictive models) to allow industry to confidently assess the overall impacts of coal quality and the economic implications during utilization.

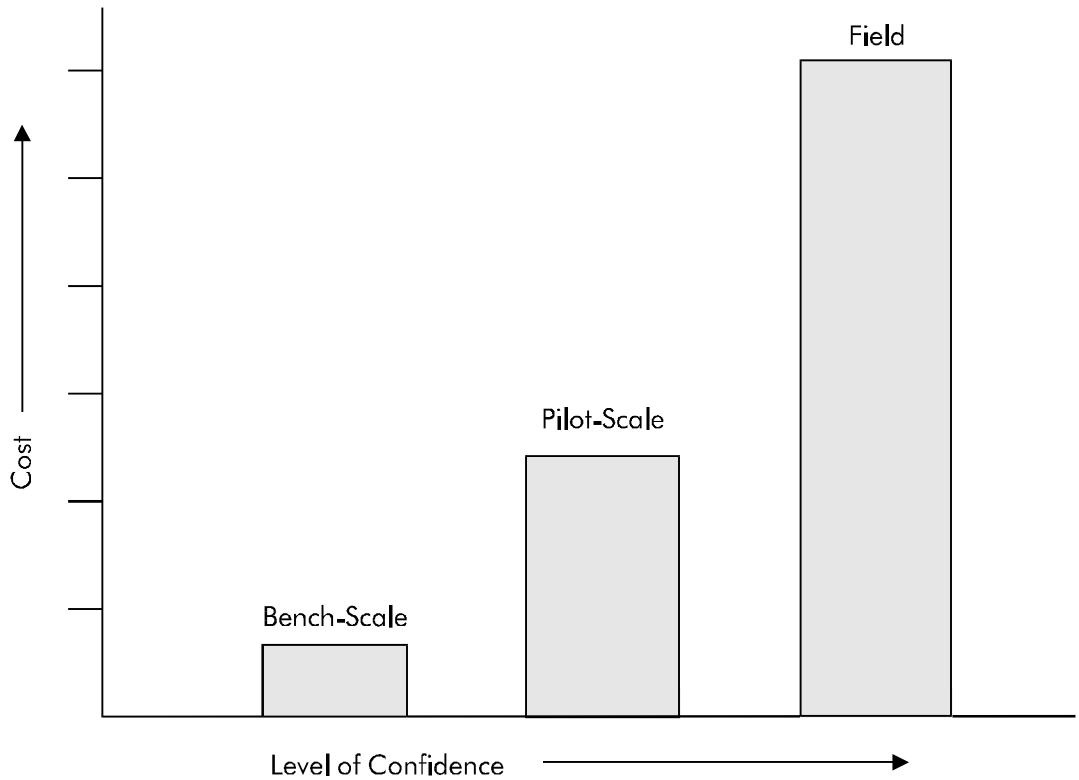


Figure 1-7
Relationship Between Testing Cost and Confidence Level of Commercial Predictions

The Significance of the CQE Tool

Fuel decisions affect nearly every aspect of power generation. Fuel buyers handle transportation issues and coal sourcing; plant engineers evaluate how individual coals behave in a unit; and environmental engineers address compliance and disposal issues. Typically, each expert uses an individual set of assumptions, data, and tools to complete an evaluation, resulting in one-dimensional pictures of fuel-related costs.

CQE integrates these assumptions, data, and tools, creating a unique electronic forum within which experts can efficiently and effectively share their knowledge and results.

The power of the forum is twofold. It not only centralizes all relevant information, it makes that information available to all other experts as appropriate. The end result of integrating a set of previously isolated analyses is a new capability that provides a complete picture of fuel-related impacts and costs.

One new capability, for instance, is CQE's ability to evaluate the economic tradeoffs between coal cleaning and scrubbing (Figure 1-8). Traditionally, utility engineers would combine results from two different models to compare the costs of cleaning and scrubbing. In contrast, a CQE analysis of cleaning versus scrubbing captures and consolidates the results of required analyses to determine the most cost-effective option or combination of options.

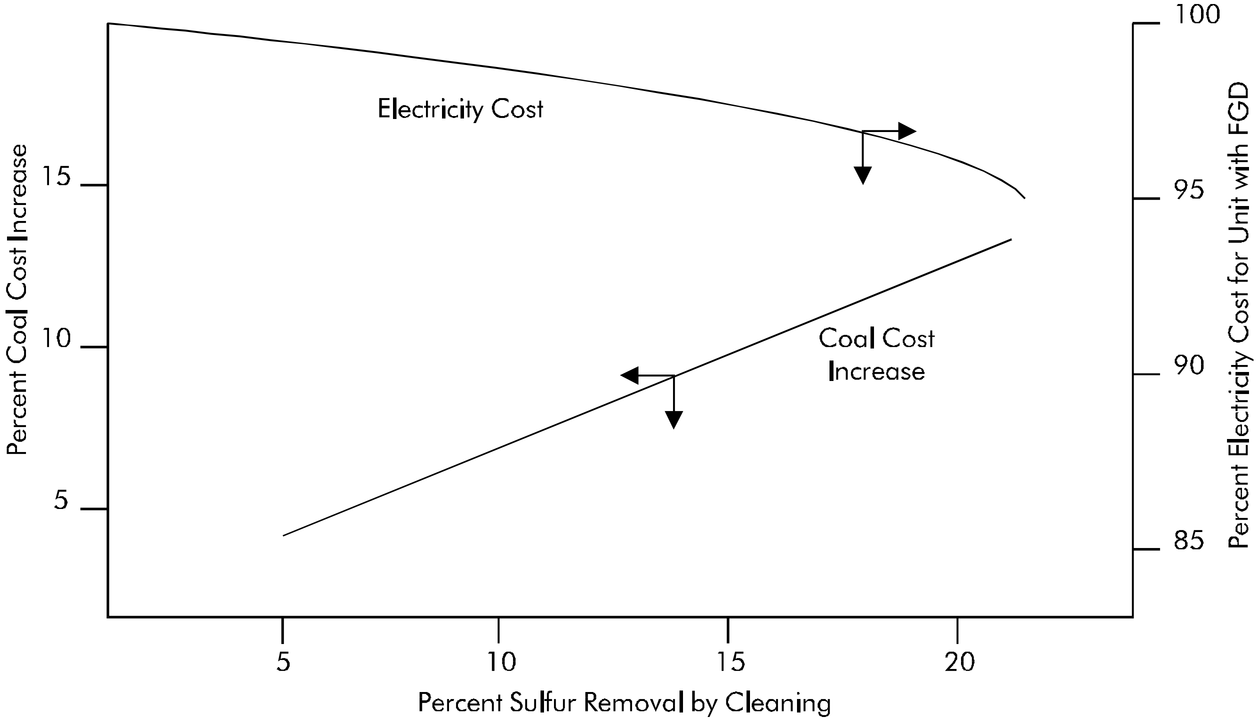


Figure 1-8
Economic Impact of Coal Cleaning

Commercial Potential and Plans

An analysis of the market for CQE shows that the most likely customers for CQE are power generation organizations, fuel suppliers, environmental organizations, government organizations, and engineering firms. These world-wide organizations can take advantage of CQE's ability to evaluate the impact of fuel quality on entire generating systems.

EPRI owns the software and distributes CQE to EPRI members for their use, and has contracted CQ Inc. as their commercialization agent. CQE is available to others in the form of three types of licenses: use, consultant, and commercialization. The largest market for use licenses with an introductory price of $90,000 is power generation organizations. Coal producers and equipment manufacturers are also prospective users. Large architect/engineering firms and boiler manufacturers are most likely to purchase consultant licenses or regional or world-wide commercialization licenses.

Black & Veatch executed the first CQE commercialization license with CQ Inc (as agent) and CQ Inc. is also licensed to commercialize CQE. Under the terms of that license, B&V and CQ Inc. are working collaboratively to sell use and consultant's licenses worldwide to provide consultation to organizations with coal quality projects and to continue the development of CQE software enhancements. Copies of CQE's stand-alone Acid Rain Advisor have been licensed to two U.S. users to date.

Conclusions and Recommendations

CQE will benefit owners and operators of coal-fired power plants in their commitments to produce energy economically and with concern for the environment. Utilities now have a tool to evaluate the system-wide consequences of fuel purchase decisions on power plant performance, emissions, and power generation costs. The software can examine potential changes in coal quality, transportation options, pulverizer performance, boiler slagging and fouling, emissions control alternatives and byproduct disposal for pulverized-coal and cyclone-fired power plants.

CQE will warrant further refinement and updating as new predictive models are validated. Future development of CQE should include coal gasification, fluidized bed boilers, European and Asian boiler design, and post combustion SO_2 and NO_x control technologies that are successfully demonstrated in U.S. Clean Coal Technology projects.

References

1. *Coal Preparation for Combustion and Conversion*, EPRI AF-791, Project 466-1 Final Report, May 1978, Gibbs & Hill Inc., NV.

2. *Impact of Coal Cleaning on the Cost of New Coal-fired Power Generation*, EPRI CS-1622, Project 1180-2 Final Report, May 1981, Bechtel National Inc., San Francisco, CA.

SELF-SCRUBBING COAL - AN INTEGRATED APPROACH TO CLEAN AIR

K. E. Harrison, P.E.
Custom Coals Corporation
Pittsburgh, PA

Presented at:

Fifth Annual Clean Coal Technology Conference
Tampa, Florida

CONTENT

INTRODUCTION AND TECHNOLOGY OVERVIEW

PROJECT DESCRIPTION

PROJECT STATUS

STARTUP AND DEBUGGING

CIRCUIT OPTIMIZATION

EQUIPMENT PERFORMANCE

PLANS FOR COMPLETING THE PROJECT

I. INTRODUCTION

On October 29, 1992, a Cooperative Agreement was executed by the United States Department of Energy (DOE) and Custom Coals Corporation (CCC). This agreement provides for the design, construction and operation of a coal preparation facility to produce Carefree Coal and Self-Scrubbing Coal, two fuels that will provide many United States utilities the opportunity to achieve compliance with the 1990 Clean Air Act Amendments (CAAA) without incurring major expenditures for power plant modifications.

Carefree Coal is coal cleaned in a proprietary dense-media cyclone circuit, using ultrafine magnetite slurries, to remove noncombustible material, including up to 90% of the pyritic sulfur. Deep cleaning alone, however, cannot produce a compliance fuel from coals with high organic sulfur contents. In these cases, Self-Scrubbing Coal will be produced. Self-Scrubbing Coal is produced in the same manner as Carefree Coal except that the finest fraction of product from the cleaning circuit is mixed with limestone-based additives and briquetted. The reduced ash content of the deeply-cleaned coal will permit the addition of relatively large amounts of sorbent without exceeding boiler ash specifications or overloading electrostatic precipitators. This additive reacts with sulfur dioxide (SO_2) during combustion of the coal to remove most of the remaining sulfur. Overall, sulfur reductions in the range of 80-90% are achieved.

After nearly 5 years of research and development of a proprietary coal cleaning technology coupled with pilot-scale validation studies of this technology and pilot-scale combustion testing of Self-Scrubbing Coal, CCC organized a team of experts to prepare a proposal in response to DOE's Round IV Program Opportunity Notice for its Clean Coal Technology Program under Public Law 101-121 and Public Law 101-512. The main objective of the demonstration project is the production of a coal fuel that will result in up to 90% reduction in sulfur emissions from coal-fired boilers at a cost competitive advantage over other technologies designed to accomplish the same sulfur emissions and over naturally occurring low sulfur coals.

II. PROJECT DESCRIPTION

The Demonstration Project, called the Laurel Facility, consists of a 500 TPH state-of-the-art, coal preparation plant and various product and raw coal handling and storage facilities. During the current project operations phase, the advanced coal cleaning cyclone and various ancillary magnetite recovery schemes are being demonstrated as well as the demonstration of combustion of the Carefree Coal and Self-Scrubbing Coal at full size power plant boilers.

Goals

CCC's goal for the project is to successfully commercialize its first plant and use that success to build a merchant coal preparation business. DOE's goal is to ensure the long term availability of a low cost, environmentally friendly fuel for our nation's long term energy needs.

Participants

The Project Team assembled to carry out the demonstration project includes:

- DOE's Project Management Team from PETC
- Custom Coals Corporation (CCC), overall project manager and lessee of patents for the technology
- Affiliated Engineering Technologies, Inc., design contractor
- Riggs Industries, Construction Managers
- Richmond Power & Light, utility host site
- Centerior Energy, utility host site
- Pennsylvania Power & Light, utility host site

III. PROJECT STATUS

- Design and construction of the facilities was completed in early 1996. Start-up began in late December 1995 and the first coal was processed on February 22, 1996. The plant circuits were fed an increasing amount of throughput and various adjustments to water and media flows were made until, in May of 1996, the facility reached its design capacity. Equipment and circuit optimization testing began immediately thereafter and have continued throughout the remainder of the year.

- One of the test burns, the Carefree Coal test at Pennsylvania Power and Light's Martins Creek Station, was conducted in mid-November. Although several of the plant circuits were performing below the expected proficiency because optimization has not been completed, the overall plant product produced for the test was consistent with the current quality of the plant feed coal.

- The later sections will detail the Start-up, the Circuit Optimization and the Equipment Performance work completed to date and provide the team's plans for completing the demonstration program.

- The project, as approved through Budget Period 3, calls for a total cost of $87,386,102, with DOE providing $37,994,437 or 43.5% of the funds. The project is expected to be completed in June 1997.

ROSEBUD SYNCOAL PARTNERSHIP
SYNCOAL® DEMONSTRATION
TECHNOLOGY UPDATE

Ray W. Sheldon, P.E.
Rosebud SynCoal Partnership
Billings, Montana

Fifth Annual Clean Coal Technology Conference
January 7-10, 1997
Tampa, Florida

SYNCOAL® PROCESS IMPROVES LOW-RANK COALS

An Advanced Coal Conversion Process (ACCP) technology being demonstrated in eastern Montana (USA) at the heart of one of the world's largest coal deposits is providing evidence that the molecular structure of low-rank coals can be altered successfully to produce a unique product for a variety of utility and industrial applications.

The product is called SynCoal® and the process has been developed by the Rosebud SynCoal Partnership (RSCP) through the U.S. Department of Energy's multi-million dollar Clean Coal Technology Program. RSCP is a Colorado (USA) general partnership formed for the purpose of conducting the Clean Coal Technology Program demonstration and the commercializing of the ACCP technology.

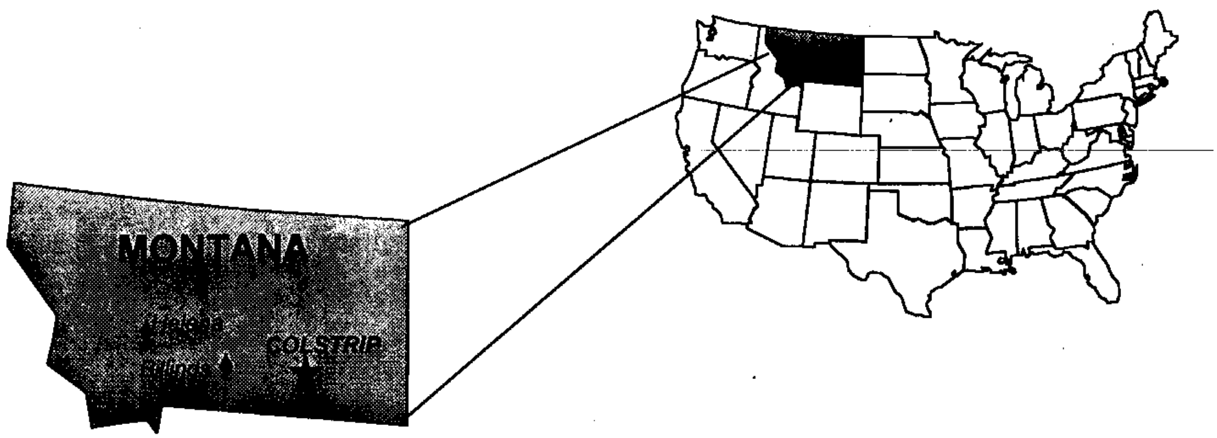
Western SynCoal Company, a subsidiary of Montana Power Company's Energy Supply Division, is the managing general partner of RSCP. The other general partner is Scoria Inc. a subsidiary of NRG Energy, the nonutility entity of Northern States Power Company of Minnesota (USA).

Montana Power Company's subsidiary, Western Energy Company, initially developed the ACCP technology and signed the original Cooperative Agreement with the Department of Energy (DOE) to build the demonstration facility under the Clean Coal Technology Program (CCT I). Western Energy then formed Western SynCoal Company and joined with Scoria. RSCP's partners own the technology in undivided interests and have exclusively licensed it to the partnership. The RSCP partnership manages the $105 million demonstration project adjacent to the Rosebud Mine at Colstrip, Montana and all activities related to technology commercialization. **(See Demo Plant Location Map)** DOE has committed $43.125 million in funding to the demonstration project. Rosebud SynCoal is responsible for all additional funding and operation of the project.

The patented ACCP process improves the heating quality of low rank coals to produce an upgraded coal produced called SynCoal®, which is a registered trademark owned by RSCP.

ADVANCED COAL CONVERSION PROCESS

Demo Plant Location



Process

The ACCP demonstration process uses low-pressure, superheated gases to process coal in vibrating fluidized beds. Two vibratory fluidized processing stages are used to heat and convert the coal. This is followed by a water spray quench and a vibratory fluidized stage to cool the coal. Pneumatic separators remove the solid impurities from the dried coal.

There are three major steps to the SynCoal® process: (1) thermal treatment of the coal in an inert atmosphere, (2) inert gas cooling of the hot coal, and (3) removal of ash minerals. **See Flow Diagram**

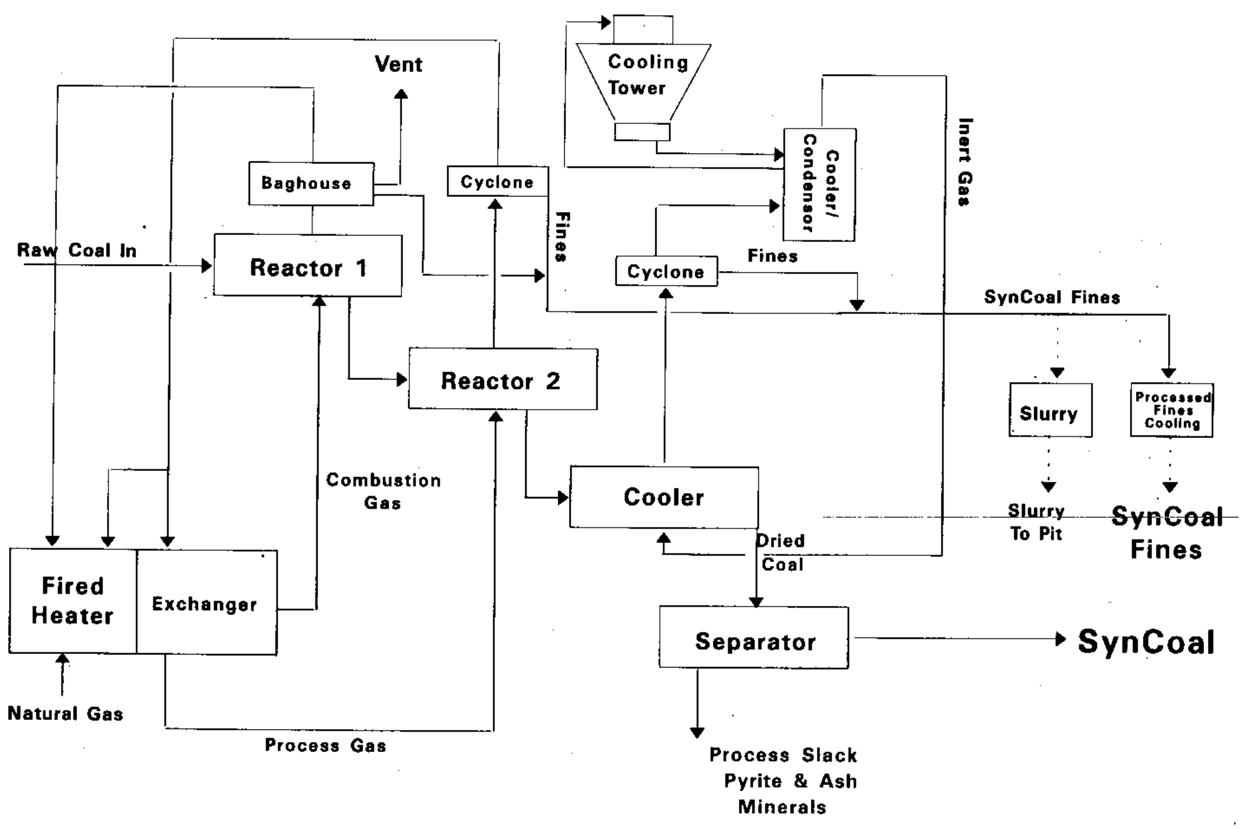
(1) During the thermal treatment process, raw coal from the stockpile is screened and fed into a two-stage thermal processing system. In the first vibratory fluidized-bed reactor, surface water is removed from the coal by heating it with hot combustion gas. When the coal exits this reactor, its temperature is slightly higher than that required to evaporate water. The coal is further heated to nearly 300°C (5° F) in a second reactor to a temperature sufficient to remove pore water and prompting decarboxylation. Here, particle shrinkage causes fracturing, destroys moisture reaction sites, and separates out the coal ash minerals.

(2) The coal then enters the coal cooler, where it is cooled to less than 150°F by contact with an inert gas (carbon dioxide and nitrogen at less than 100°F) in a vibrating fluidized bed cooler.

(3) In the last stage -- the coal cleaning system -- cooled coal is fed to deep bed stratifiers where air velocity and vibration separate mineral matter from the coal with rough gravity separation. The low specific gravity fractions are sent to a product conveyor while heavier specific gravity fractions go to fluidized bed separators, for additional ash removal. Fines from various parts of the cleaning process are collected in baghouses and cyclones, cooled and made available as an additional product line.

The SynCoal® is a high quality product with less than 5 percent moisture, sulfur content of 0.5 percent, ash content of about 9 percent, and a heating value of about 11,800 Btu per pound.

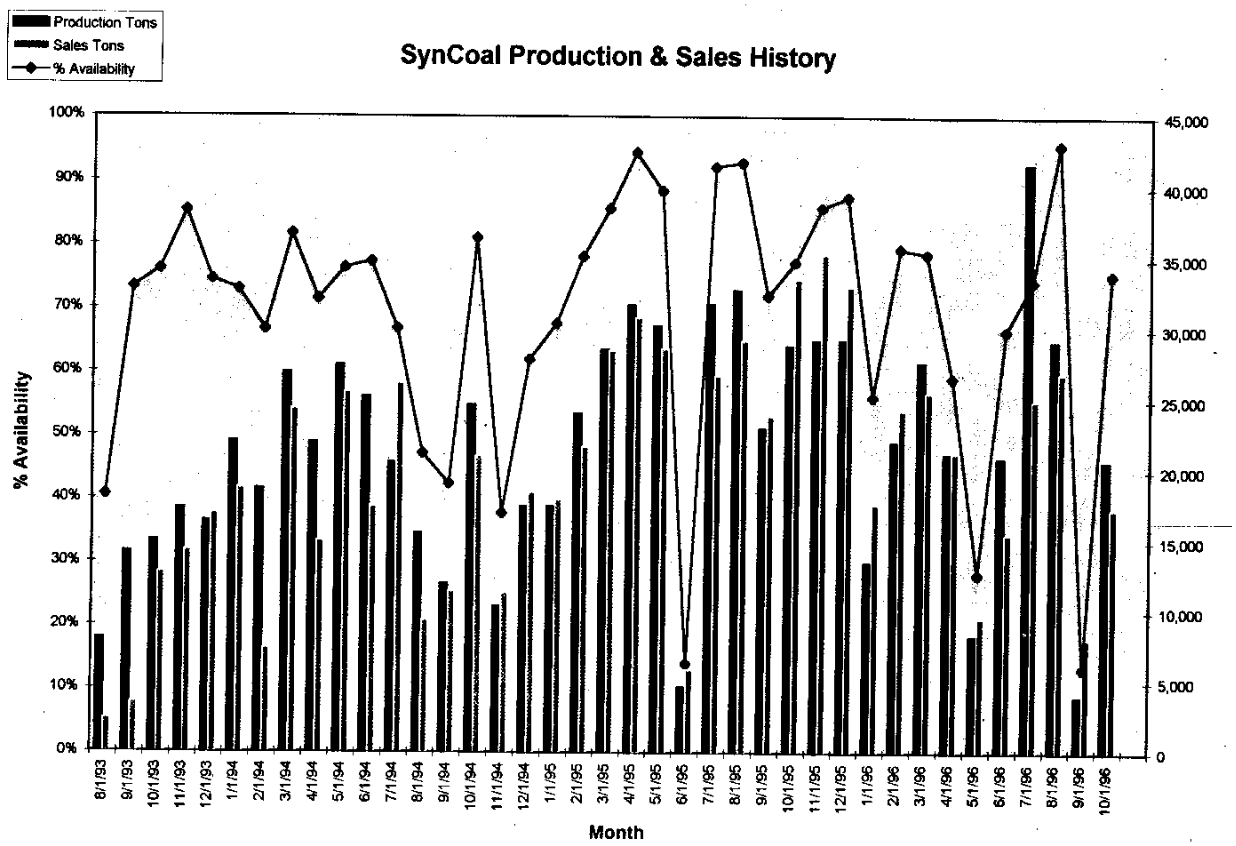
Process Flow Diagram



When operated continuously, the demonstration plant produces over 1,000 tons per day (up to 300,000 tons per year) of SynCoal® with a 2% moisture content, approximately 11,800 Btu/lb and less than 1.0 pound of SO_2 per million Btu . This product is obtained from Rosebud Mine sub-bituminous coal which starts with 25% moisture, 8,600 Btu/lb and approximately 1.6 pounds of SO_2 per million Btu.

Nearly 1.3 million tons of raw coal has been processed and over 850,000 tons of

SynCoal® has been produced through October 1996. The plant has consistently operated at over 100% of design capacity and over 75% availability. **See SynCoal Production and Sales History and Monthly Operating Statistics**



ACCP MONTHLY OPERATING STATISTICS

MONTH	PRODUCTION AVAILABILITY	FORCED OUTAGE RATE	TONS PROCESSED	CAPACITY FACTOR	SHIPMENTS
Mar-92	4%	96%	700	2%	181
Apr-92	7%	89%	411	1%	212
May-92	12%	76%	2,757	7%	0
Jun-92	13%	81%	2,496	7%	214
Jul-92	7%	56%	1,436	4%	0
Aug-92	17%	60%	1,860	5%	61
Sep-92	44%	33%	8,725	24%	1,672
Oct-92	13%	63%	2,292	6%	523
Nov-92	58%	28%	6,946	19%	2,386
Dec-92	11%	80%	1,063	3%	317
Jan-93	53%	26%	8,626	23%	3,658
Feb-93	44%	18%	6,544	19%	915
Mar-93	44%	34%	6,565	17%	629
Apr-93	49%	30%	8,514	23%	745
May-93	47%	39%	9,256	24%	768
Jun-93	15%	26%	2,752	7%	199
Jul-93	0%		0	0%	655
Aug-93	41%	43%	13,427	35%	2,361
Sep-93	73%	18%	23,276	63%	3,528
Oct-93	76%	11%	24,606	64%	12,753
Nov-93	85%	14%	27,927	76%	14,349
Dec-93	74%	9%	26,009	68%	16,951
Jan-94	73%	17%	34,979	92%	19,093
Feb-94	67%	28%	29,247	85%	7,909
Mar-94	82%	14%	41,891	10%	24,627
Apr-94	72%	27%	33,686	91%	15,622
May-94	76%	8%	39,404	103%	26,415
Jun-94	77%	23%	36,657	99%	18,873
Jul-94	67%	33%	34,026	89%	26,527
Aug-94	47%	19%	24,645	64%	9,146
Sep-94	42%	35%	20,327	55%	11,408
Oct-94	81%	16%	34,908	91%	19,161
Nov-94	38%	62%	16,418	44%	11,169
Dec-94	62%	27%	25,258	66%	18,478
Jan-95	68%	32%	31,726	83%	17,695
Feb-95	78%	22%	38,325	111%	21,710
Mar-95	86%	4%	42,674	112%	28,548
Apr-95	94%	1%	47,818	129%	30,827

MONTH	PRODUCTION AVAILABILITY	FORCED OUTAGE RATE	TONS PROCESSED	CAPACITY FACTOR	SHIPMENTS
May-95	88%	5%	43,752	114%	28,674
Jun-95	14%	26%	7,142	19%	5,859
Jul-95	92%	8%	48,512	127%	26,795
Aug-95	93%	4%	48,889	128%	29,261
Sep-95	72%	28%	37,129	100%	23,954
Oct-95	77%	10%	43,316	113%	33,614
Nov-95	86%	14%	42,807	116%	35,380
Dec-95	88%	13%	47,531	124%	33,101
Jan-96	56%	44%	24,710	65%	17,662
Feb-96	79%	21%	36,280	101%	24,340
Mar-96	79%	21%	39,071	104%	25,566
Apr-96	59%	19%	30,038	81%	21,321
May-96	28%	11%	13,282	35%	9,571
Jun-96	67%	21%	31,775	85%	15,553
Jul-96	74%	26%	35,056	92%	24,998
Aug-96	96%	4%	43,832	117%	29,200
Sept-96	13%	33%	6,117	16%	8,112
Oct-96	75%	25%	33,730	90%	17,375
	TOTAL		1,331,146		780,621

Utility Applications - Customer Results

A SynCoal® test-burn was completed at the 160 MW. J.E. Corette plant in Billings, Montana. A total of 204,478 tons of SynCoal® was burned between mid 1992 and April, 1996. The testing involved both handling and combustion of SynCoal® in a variety of blends. These blends ranged from approximately 15% SynCoal® to approximately 85% SynCoal®. Overall the results indicated that a 50% DSE SynCoal®/raw coal blend provided improved results with SO_2 emissions reduced by 21% overall, generation increased at normal operating loads and no noticeable impact on NOx emissions. DSE is a treatment to improve SynCoal®'s bulk handling characteristics when using conventional handling techniques. It controls dusting of the product and provides temporary resistance to spontaneous combustion.

Additionally SynCoal® deslagged the boiler at full load eliminating costly ash shedding operations and provided reduced gas flow resistance in the boiler and convection passage, reducing fan horsepower and improving heat transfer in the boiler area, resulting in increased generation by approximately 3 megawatts on a net basis

Deliveries of SynCoal® are now being sent to Colstrip Project Units 1 & 2 in Colstrip, Montana. Testing has begun on the use of SynCoal® in these twin 320-megawatt pulverized coal fired plants. The results of these tests will provide information on: boiler efficiency, output, and air emissions. A total of 61,339 tons have been consumed to date.

A new SynCoal® delivery system is being designed which, if installed, would provide selectively controlled pneumatic delivery of SynCoal® to pulverizers individual pulverizers in the two units. This system would allow controlled tests in the two units providing valuable test data on emissions, performance and slagging. The use of both units operating at similar loads and with the same raw coal would provide a unique opportunity to perform directly comparative testing.

In May 1993, 190 tons of Center, North Dakota lignite was processed at the ACCP demonstration facility in Colstrip, producing 10,740 Btu/lb product and 47% reduction in sulfur and a 7% percent reduction in ash. In September 1993, a second test was performed processing 532 tons of lignite, producing a 10,567 Btu/lb product with a 48% sulfur reduction and a 27% ash reduction. The Center lignite before beneficiation had 36% moisture, approximately 6,800 Btu/lb at about 3.0 lbs of SO_2 per million Btu.

Approximately 190 tons of these upgraded products produced in September was returned two days later to the Milton R. Young Unit #1 and burned in an initial test showing dramatic improvement in cyclone combustion, improved slag tapping and a 13% reduction in boiler air flow, reducing the auxiliary power loads on the forced draft and induced draft fans. Additionally the boiler efficiency increased from 82% to in excess of 86% and the total gross heat rate improved by 123 Btu/kWh hour.

The operation of the cyclone units at the Milton R. Young facility are plagued by cyclone barrel slagging which is typically removed by burning additional No. 2 fuel oil. These units also slag and foul in the boiler and convective passes requiring complete shutdown and cold boiler washing between three and four times a year.

In an effort to reduce these detrimental effects, Minnkota Power has tested the use of SynCoal® as a substitute for fuel oil when removing cyclone slag and also as a steady additive to reduce the boiler slagging and convective fouling to reduce the number of cold boiler washings necessary. The fuel oil substitute testing nicknamed "Klinker Killer" has been successfully tested showing the SynCoal® is at least as effective in removing cyclone barrel clinkers on a Btu for Btu basis as fuel oil. The SynCoal® produces a much higher temperature in the cyclone barrel than lignite increasing the cyclone barrel front wall temperature as much as 900° F and more closely matched the design temperature profile which improves the cyclone combustion operation dramatically.

The testing to support the long term objective has indicated that SynCoal® would be effective in this application although the limited duration of these tests has left them less than fully conclusive.

Industry Applications - Customer Results

Several industrial cement and lime plants have been customers of SynCoal® for an extended period of time. A total of 129,056 tons have been delivered to these customers from 1993 through October 1996. In their testing and use of SynCoal® they have found that it improves their production from their direct fired kiln applications. These improvements are both in capacity and product quality as the steady flame produced by SynCoal® appears to allow tighter process control and process optimization in their operations.

A bentonite producer has been using SynCoal® as an additive in their green sand molding product for use in the foundry industry. The bentonite company has used SynCoal® since 1993 and has taken approximately 30,569 tons. SynCoal® has been found to be a very consistent product allowing their customers to reduce the quantity of additives used and improving the quality of the metal casting produced.

Commercialization

Western SynCoal Company has moved closer to building a $37.5 million commercial SynCoal plant at Minnkota's Milton R. Young Power Station near Center, North Dakota. Minnkota is a generation and transmission cooperative supplying wholesale electricity to 12 rural electric cooperatives in eastern North Dakota and northwestern Minnesota.

Minnkota owns and operates the 250-megawatt Unit 1 at the Young Station, and operates the 438-mw Unit 2 which is owned by Square Butte Electric Cooperative of Grand Forks. This power station is already one of the lowest cost electric generating plants in the nation; however, with the use of SynCoal® the operations of the plant could further improve.

The SynCoal plant would produce an estimated 403,000 tons of finished product annually, which would be blended with the lignite. The reduced slagging and fouling improves generating plant maintenance and allows potentially longer runs between downtimes to ultimately produce more electricity. The process is anticipated to boost the lignite heating value by 60 percent and could lower its sulfur content by 50 percent with an anticipated second phase of the project.

International

RSCP has been actively marketing and promoting the SynCoal® technology world-wide. RSCP has been working closely with a Japanese equipment and technology company to expand into Asian markets. Prospects are also being pursued in Europe currently.

Summary

Rosebud SynCoal is continuing to advance the SynCoal® technology in a prudent and organized manner. The work to date has made SynCoal® the most advanced Low Rank Coal upgrading technology available and has put it on the cusp of commercial viability. The successful conclusion of the Center SynCoal Project and the enhanced SynCoal® delivery system and testing in Colstrip will position SynCoal® to be a viable option to enhance low rank coal fired utility operations.

AN UPDATE ON
BLAST FURNACE
GRANULAR COAL INJECTION

D. G. Hill
Bethlehem Steel Corporation
Burns Harbor Division
Burns Harbor, IN 46304

T. J. Strayer and R. W. Bouman
Bethlehem Steel Corporation
Bethlehem, PA 18016

ABSTRACT

A blast furnace coal injection system has been constructed and is being used on the furnaces at the Burns Harbor Division of Bethlehem Steel. The injection system was designed to deliver both granular (coarse) and pulverized (fine) coal. Construction was completed on schedule in early 1995. Coal injection rates on the two Burns Harbor furnaces were increased throughout 1995 and was over 200 lbs/ton on C furnace in September. The injection rate on C furnace reached 270 lbs/ton by mid-1996. A comparison of high volatile and low volatile coals as injectants shows that low volatile coal replaces more coke and results in a better blast furnace operation. The replacement ratio with low volatile coal is 0.96 lbs coke per pound of coal. A major conclusion of the work to date is that granular coal injection performs very well in large blast furnaces. Future testing will include a processed sub-bituminous coal, a high ash coal and a direct comparison of granular versus pulverized coal injection.

I. INTRODUCTION

A blast furnace coal injection system has been installed at the Burns Harbor Division of Bethlehem Steel Corporation. This is the first blast furnace coal injection system in the US that has been designed to deliver granular (coarse) coal - all previously installed blast furnace coal injection systems in the US have been designed to deliver pulverized (fine) coal. Financial assistance for the coal injection system was provided by the Clean Coal Technology Program.

The use of granular coal in blast furnaces was jointly developed by British Steel and Simon-Macawber (now CPC-Macawber) and used at the Scunthorpe Works in England. The blast furnaces at Scunthorpe have about one-half the production capability of the Burns Harbor blast furnaces. Therefore, one of the main objectives of the Clean Coal Technology (CCT) test program at Burns Harbor is to determine the effect of granular coal injection on large high productivity blast furnaces. Another objective of the CCT test program at Burns Harbor is to determine the effect of different types of US coals on blast furnace performance.

The Burns Harbor Plant produces flat rolled steel products for the automotive, machinery and construction markets. The Plant is located on the southern shore of Lake Michigan about 30 miles east of Chicago. Burns Harbor is an integrated operation that includes two coke oven batteries, an iron ore sintering plant, two blast furnaces, a three vessel BOF shop and two twin-strand slab casting machines. These primary facilities can produce over five million tons of raw steel per year. The steel finishing facilities at Burns Harbor include a hot strip mill, two plate mills, a cold tandem mill complex and a hot dip coating line.

When originally designed and laid-out, the Burns Harbor Plant could produce all the coke required for the two blast furnaces operating at 10,000 tons/day. However, improved practices and raw materials have resulted in a blast furnace operation that now can produce over 14,000 tons/day. Since the coke oven batteries are not able to produce the coke required for a 14,000 ton/day blast furnace output, other sources of coke and energy have been used to fill the gap. Over the years, coke has been shipped to Burns Harbor from other Bethlehem plants and from outside coke suppliers. In addition, auxiliary fuels have been injected into the furnaces to reduce the coke requirements. The auxiliary fuels have included coal tar, fuel oil and natural gas. The most successful auxiliary fuel through the 1980s and early 1990s has been natural gas. It is easy to inject and, at moderate injection levels, has a highly beneficial effect on blast furnace operations and performance. However, there are two significant problems with the use of natural gas in blast furnaces. One problem is the cost and the other is the amount that can be injected and, therefore, the amount of coke that can be replaced. Our process and economic studies showed that more coke could be replaced and iron costs could be reduced by injecting coal instead of natural gas in the Burns Harbor furnaces.

This led Bethlehem to submit a proposal to the DOE to conduct a comprehensive assessment of coal injection at Burns Harbor. Following an extensive review by the DOE, Bethlehem's Blast Furnace Granular Coal Injection System Demonstration Project was one of thirteen demonstration projects accepted for funding in the Clean Coal Technology Program third round of competition. The primary thrust of the project is to demonstrate commercial performance characteristics of granular coal as a supplemental fuel for steel industry blast furnaces. The technology will be demonstrated on large high productivity blast furnaces using a wide range of coal types available in the US. The planned tests will assess the impact of coal particle size distribution as well as chemistry on the amount of coal that can be injected effectively. Upon successful completion of the work, the results will provide the information and confidence needed by others to assess the technical and economic advantages of applying the technology to their own facilities.

A major consideration in evaluating coal injection in the US is the aging capacity of existing cokemaking facilities and the high capital cost to rebuild these facilities to meet emission guidelines under the Clean Air Act Amendments. The increasingly stringent environmental regulations and the continuing decline in domestic cokemaking capability will cause significant reductions in the availability of commercial coke over the coming years. Due to this decline in availability and increase in operating and maintenance costs for domestic cokemaking facilities, commercial coke prices are projected to increase by more than general inflation. Higher levels of blast furnace injectants, such as coal, enable domestic integrated steel producers to minimize their dependence on coke.

Blast Furnace Process

The ironmaking blast furnace is at the heart of integrated steelmaking operations. As shown in Figure 1, the raw materials are charged to the top of the furnace through a lock hopper arrangement to prevent the escape of pressurized hot reducing gases. Air needed for the combustion of coke to generate the heat and reducing gases for the process is passed through stoves and heated to 1500-2300ºF. The heated air (hot blast) is conveyed to a refractory-lined bustle pipe located around the perimeter of the furnace. The hot blast then enters the furnace through a series of ports (tuyeres) around and near the base of the furnace. The molten iron and slag are discharged through openings (tapholes) located below the tuyeres. The molten iron flows to refractory-lined ladles for transport to the basic oxygen furnaces.

A schematic showing the various zones inside the blast furnace is shown in Figure 2. As can be seen, the raw materials, which are charged to the furnace in batches, create discrete layers of ore and coke. As the hot blast reacts with and consumes coke at the tuyere zone, the burden descends in the furnace resulting in a molten pool of iron flowing around unburned coke just above the furnace bottom (bosh area). Reduction of the descending ore occurs by reaction with the rising hot reducing gas that is formed when coke is burned at the tuyeres.

The cohesive zone directly above the tuyeres is so called because it is in this area that the partially reduced ore is being melted and passes through layers of coke. The coke layers provide the permeability needed for the hot gases to pass through this zone to the upper portion of the furnace. Unlike coal, coke has the high temperature properties needed to retain its integrity in this region and is the reason that blast furnaces cannot be operated without coke in the burden.

The hot gas leaving the top of the furnace is cooled and cleaned. Since it has a significant heating value (80-100 Btu/scf), it is used to fire the hot blast stoves. The excess is used to generate steam and power for other uses within the plant.

II. COAL INJECTION TECHNOLOGY

Bethlehem decided to utilize the CPC Macawber Blast Furnace Granular Coal Injection (BFGCI) System, because unlike more widely used systems that utilize only pulverized coal, it is capable of injecting both granular and pulverized coal. Bethlehem believes that the CPC Macawber system offers a variety of technical and economic advantages which make this system potentially very attractive for application in the US basic steel industry. A schematic showing the application of the technology to the blast furnace is shown in Figure 3. Some of the advantages of this technology include:

FIGURE 1

THE BLAST FURNACE COMPLEX

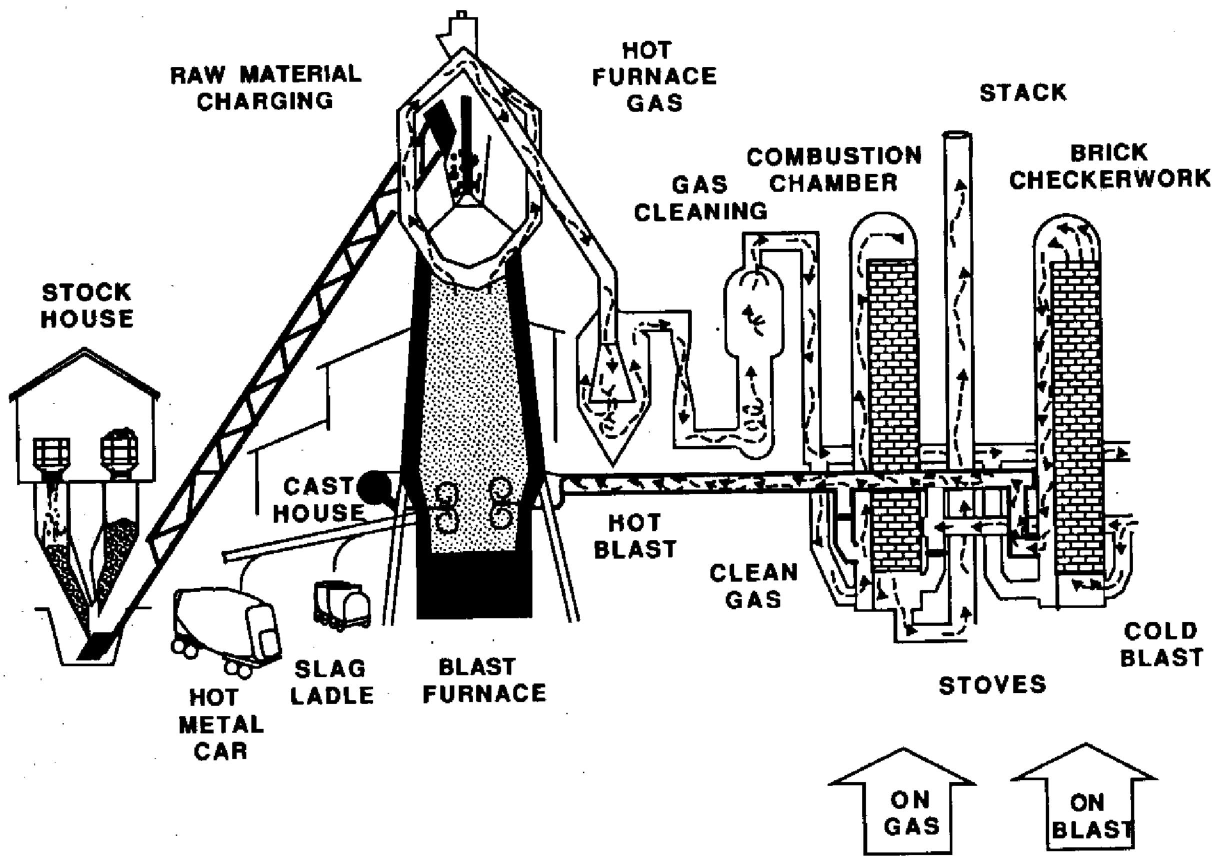


FIGURE 2

ZONES IN THE BLAST FURNACE

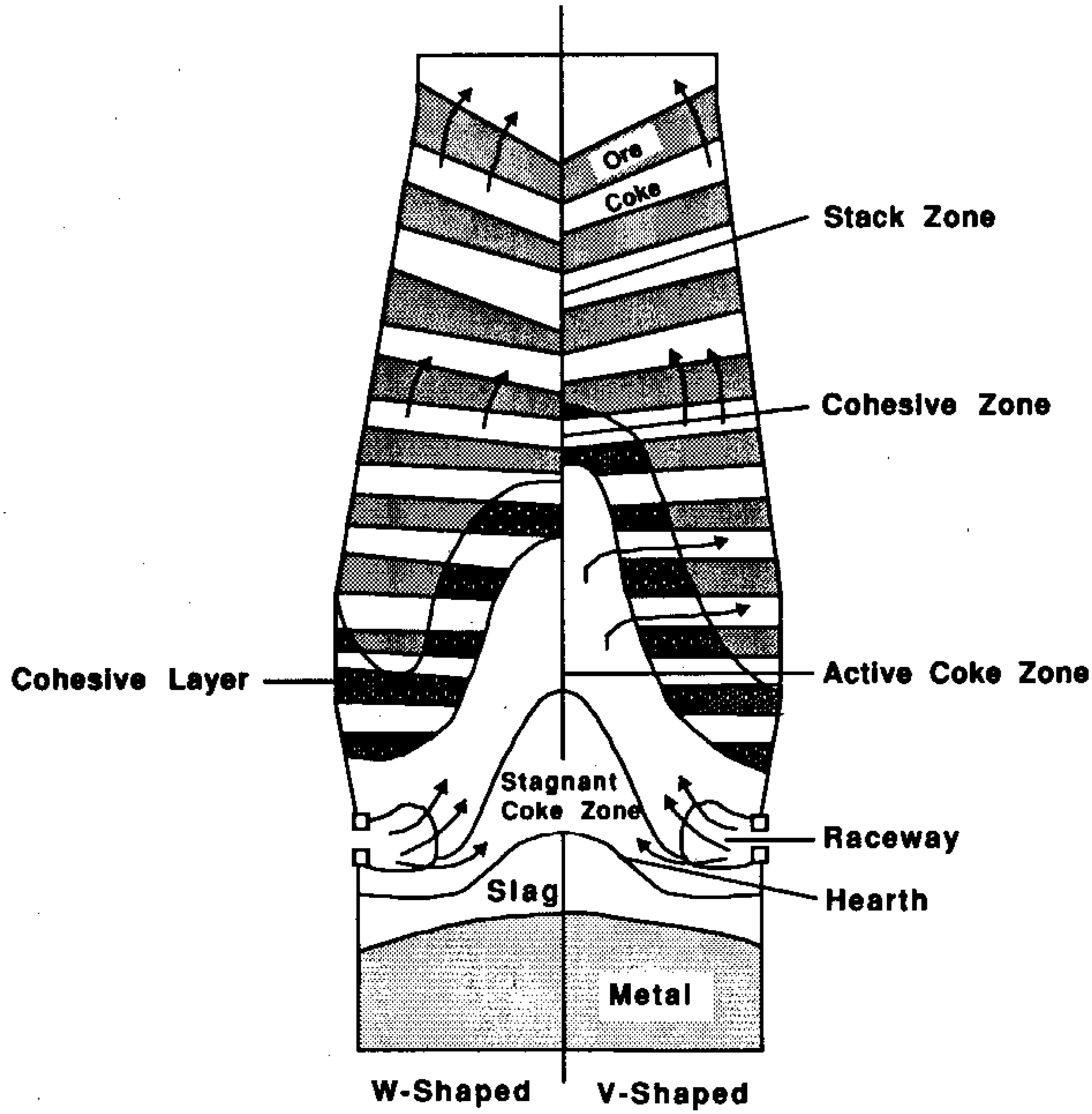
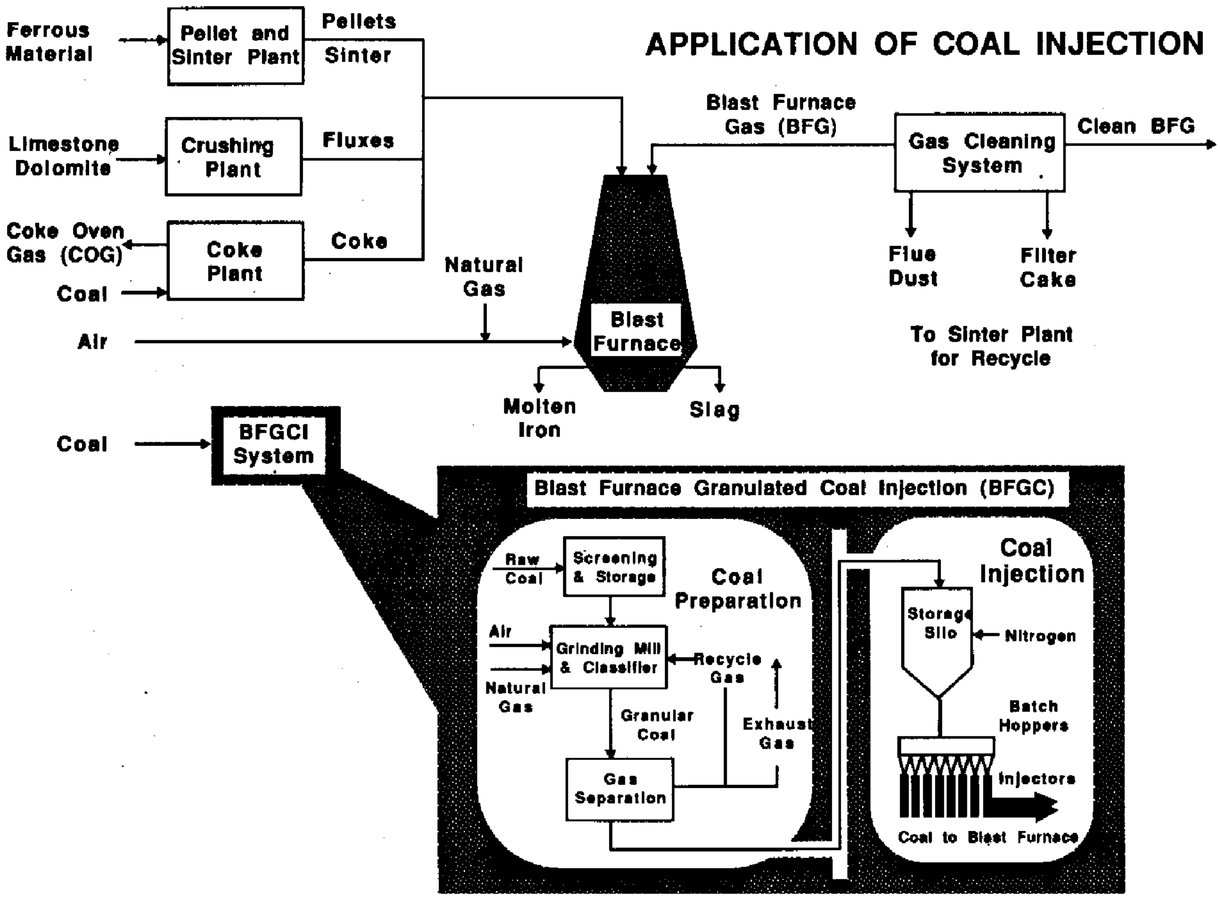


FIGURE 3

APPLICATION OF COAL INJECTION



- The injection system has been used with granular coal as well as with pulverized coal. No other system has been utilized over this range of coal sizes. Granular coal is 10-30% minus 200 mesh whereas pulverized coal is 70-80% minus 200 mesh.

- The costs for granular coal preparation systems are less than those for the same capacity pulverized coal systems.

- Granular coal is easier to handle in pneumatic conveying systems. Granular coals are not as likely to stick to conveying pipes if moisture control is not adequately maintained.

- Coke replacement ratios obtained by British Steel have not been bettered in any worldwide installation.

- System availability has exceeded 99 percent during several years of operation at British Steel.

- The unique variable speed, positive displacement CPC Macawber injectors provide superior flow control and measurement compared to other coal injection systems.

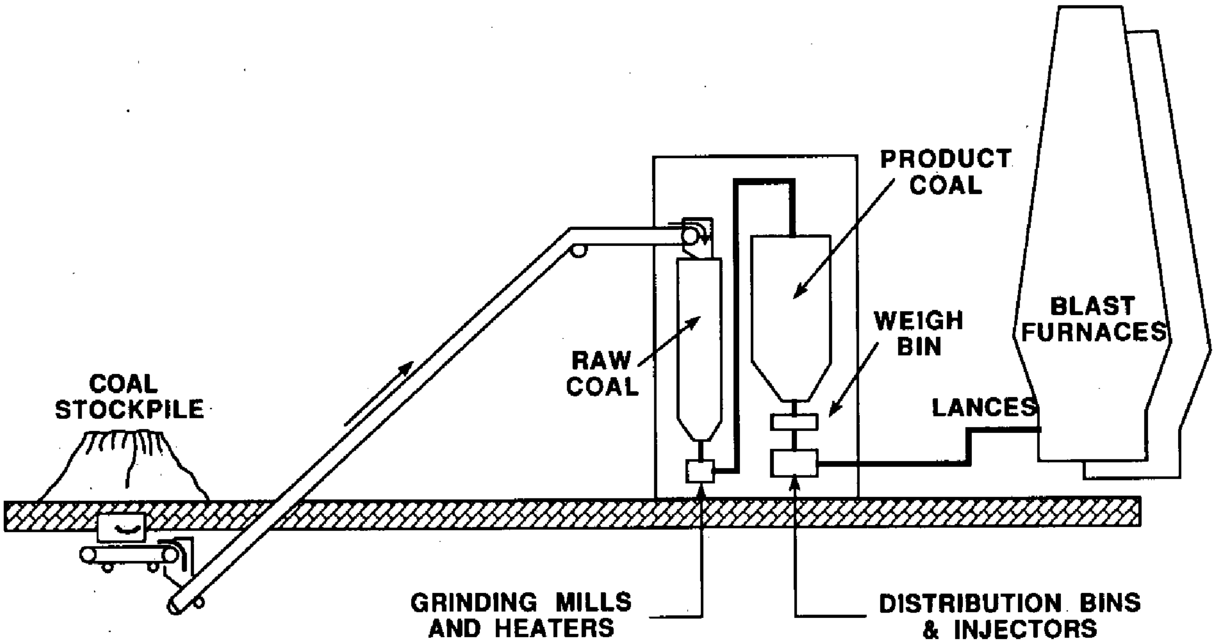
The joint development by British Steel and CPC Macawber of a process for the injection of granular coal into blast furnaces began in 1982 on the Queen Mary blast furnace at the Scunthorpe Works.(1,2) The objective of the development work was to inject granular coal into the furnace and test the performance of the CPC Macawber equipment with a wide range of coal sizes and specifications. Based on Queen Mary's performance, coal injection systems were installed on Scunthorpe's Queen Victoria, Queen Anne and Queen Bess blast furnaces and on Blast Furnaces 1 and 2 of the Ravenscraig Works. Queen Victoria's system was brought on line in November, 1984 and Queen Anne's in January, 1985. The Ravenscraig systems were started up in 1988. The success of the GCI systems at Scunthorpe and Ravenscraig led Bethlehem to conclude that the system could be applied successfully to large blast furnaces using domestic coals.

IV. INSTALLATION DESCRIPTION

A simplified flow diagram of the coal handling system at Burns Harbor is shown in Figure 4. The Raw Coal Handling Equipment and the Coal Preparation Facility includes the equipment utilized for the transportation and preparation of the coal from an existing railroad car dumper until it is prepared and stored prior to passage into the Coal Injection Facility; the Coal Injection Facility delivers the prepared coal to the blast furnace tuyeres.

Raw Coal Handling. Coal for this project is transported by rail from coal mines to Burns Harbor similar to the way in which the plant now receives coal shipments for the coke ovens. The coal is

FIGURE 4. COAL PREPARATION AND INJECTION FACILITIES
BURNS HARBOR PLANT



unloaded using a railroad car dumper, which is part of the blast furnace material handling system. A modification to the material handling system was made to enable the coal to reach either the coke ovens or the coal pile for use at the Coal Preparation Facility.

Raw Coal Reclaim. The raw coal reclaim tunnel beneath the coal storage pile contains four reclaim hoppers in the top of the tunnel. The reclaim hoppers, which are directly beneath the coal pile, feed a conveyor in the tunnel. The reclaim conveyor transports the coal at a rate of 400 tons per hour above ground to the south of the storage pile. A magnetic separator is located at the tail end of the conveyor to remove tramp ferrous metals. The conveyor discharges the coal onto a vibrating screen to separate coal over 2 inches from the main stream of minus 2-inch coal. The oversized coal passes through a precrusher which discharges minus 2-inch coal. The coal from the precrusher joins the coal that passes through the screen and is conveyed from ground level by a plant feed conveyor to the top of the building that houses the Coal Preparation Facility.

Coal Preparation. The plant feed conveyor terminates at the top of the process building that houses the Coal Preparation Facility. Coal is transferred to a distribution conveyor, which enables the coal to be discharged into either of two steel raw coal storage silos. The raw coal silos are cylindrical with conical bottoms and are completely enclosed with a vent filter on top. Each silo holds 240 tons of coal, which is a four-hour capacity at maximum injection levels. Air cannons are located in the conical section to loosen the coal to assure that mass flow is maintained through the silo.

Coal from each raw coal silo flows into a feeder which controls the flow of coal to the preparation mill. In the preparation mill, the coal is ground to the desired particle size. Products of combustion from a natural gas fired burner are mixed with recycled air from the downstream side of the process and are swept through the mill grinding chamber. The air lifts the ground coal from the mill vertically through a classifier where oversized particles are circulated back to the mill for further grinding. The proper sized particles are carried away from the mill in a 52-inch pipe. During this transport phase, the coal is dried to 1-1.5% moisture. The drying gas is controlled to maintain oxygen levels below combustible levels. There are two grinding mill systems; each system produces 30 tons per hour of pulverized coal or 60 tons per hour of granular coal.

The prepared coal is then screened to remove any remaining oversize material. Below the screens, screw feeders transport the product coal into one of four 180-ton product storage silos and then into a weigh hopper in two-ton batches. The two-ton batches are dumped from the weigh hopper into the distribution bins which are part of the Coal Injection Facility.

Coal Injection. The Coal Injection Facility includes four distribution bins located under the weigh hoppers described above. Each distribution bin contains 14 conical-shaped pant legs. Each pant leg feeds an injector which allows small amounts of coal to pass continually to an injection line. Inside the injection line, the coal is mixed with high-pressure air and is carried through approximately 600 feet of 1-1/2-inch pipe to an injection lance mounted on each of the 28 blowpipes at each furnace. At the injection lance tip, the coal is mixed with the hot blast and carried into the furnace raceway. The 14 injectors at the bottom of the distribution bin feed alternate furnace tuyeres. Each furnace requires two parallel series of equipment, each containing one product coal silo, one weigh hopper, one distribution bin and 14 injector systems.

V. PROJECT MANAGEMENT

The demonstration project is divided into three phases:

Phase I	Design
Phase II	Construction and Start-up
Phase III	Operation and Testing

Phase I was completed in December 1993 and construction was completed in January 1995. Coal was first injected in four tuyeres of D furnace on December 18, 1994. The start-up period continued to November 1995 at which time the operating and testing program started. The testing of coals (Phase III) is expected to continue to July 1998.

The estimated project cost summary is shown in Table I. The total cost is expected to be about $191 million. Additional information on project management was presented at the previous CCT Conferences. (3,4)

<u>Facility Start-Up</u>

The coal injection facilities were fully started in January 1995 and by early June the coal injection rate on both furnaces had stabilized at 140 lbs/ton.(5) There were facility start-up problems in January and February, but by mid-year the coal preparation and delivery systems were operating as designed. The injection rate on C furnace was increased through the summer months and was over 200 lbs/ton for September, October and November. The injection rate on D furnace was kept in the range of 145-150 lbs/ton during the second half of the year.

In December 1995, severe coal weather caused coal handling and preparation problems that were not experienced during start-up in early 1995. The most severe problem was due to moisture condensing on the inside walls of the prepared coal silos. The moisture caked the coal and eventually blocked the injectors below the silos. As a result, coal injection on C furnace was stopped in mid-December and the coal silos were emptied and cleaned. In order to prevent condensation in the future, the top and sides of the C furnace coal silos were insulated. The D furnace silos were insulated in January 1996. The insulation has prevented any reoccurrence of blocked injectors due to caked coal.

VI. TEST PROGRAM

The objective of the overall test program is to determine the effect of coal grind and coal type on blast furnace performance. The start-up operation was conducted with a high volatile coal from eastern Kentucky with 36% volatile matter, 8% ash and 0.63% sulfur. The coal preparation

system was operated to provide granular coal throughout the start-up period.
The coal injection rates and coke rates for C and D furnaces during 1995 and 1996 are shown in Figures 5 and 6, respectively.

Initial Results with Granular Coal

The first comparison of interest was the blast furnace results with coal injection versus natural gas injection. A typical monthly operating period with natural gas is shown in Table II along with the first full month (April 1995) of coal injection on D furnace. The coke rate during the initial period with coal injection at 150 lbs/ton was 55 lbs greater than with natural gas at 140 lbs/ton. This was not unexpected. It has been established in the past that 1.3 to 1.4 lbs of coke are replaced by one pound of natural gas. The initial expectation for injected coal was that 0.8-0.9 lbs of coke would be replaced by one pound of coal. Also notable in Table II is the 44 lbs/ton slag volume increase that accompanies the injected coal practice. This additional slag volume is a direct result of the coal ash. Slag sulfur also increased from 0.87% to 1.09% due to the sulfur in the coal. In order to maintain hot metal chemistry control, the slag chemistry has been altered slightly to provide more sulfur removal capacity. Another item of interest is the large decrease in the hydrogen content of the top gas when coal is injected.

The next process benchmark that was important to operating personnel was the amount of injected coal necessary to return the furnace coke rate to the levels previously experienced with natural gas. This is shown by the September 1995 operating data from C furnace in Table II. After gaining experience with coal injection and establishing a steady operation at the coal preparation facility, an injection rate of 210 lbs/ton resulted in a comparable coke rate to the natural gas experience. The September operation is notable with regard to several process parameters. The wind rate has been reduced along with an increase in the oxygen enrichment level. Increasing the oxygen content of the hot blast resulted in a higher flame temperature which, in turn, enhances coal combustion in the tuyere zone. The flame temperature increased by 270 F with coal injection versus the previous practice with natural gas. Slag volume and chemistry have changed very little except for the higher sulfur content that is directly proportional to the increased injected coal rate. A decrease in the furnace permeability during this period is also apparent.

Permeability is a parameter used to show the amount of hot blast that is blown at a given pressure drop through the furnace. In general, a higher permeability means the flow of reducing gases through the furnace is smoother. The increase in coal injection from 150 to 210 lbs/ton caused a significant reduction in the furnace permeability. Figure 7 shows the effect of coal injection on permeability in both furnaces through July 1996. The reduction of furnace permeability is a major concern for higher levels of coal injection.

Table III shows the coals used during 1995 at Burns Harbor. The most important difference between the eastern Kentucky high volatile coal and the low volatile coals is the total carbon content. The effect of higher coal carbon content is shown with the blast furnace results from November 1994 and April 1995 in Table IV. The coke rate is about 50 lbs/ton lower with the low volatile coals compared to the high volatile coal.

FIGURE 5

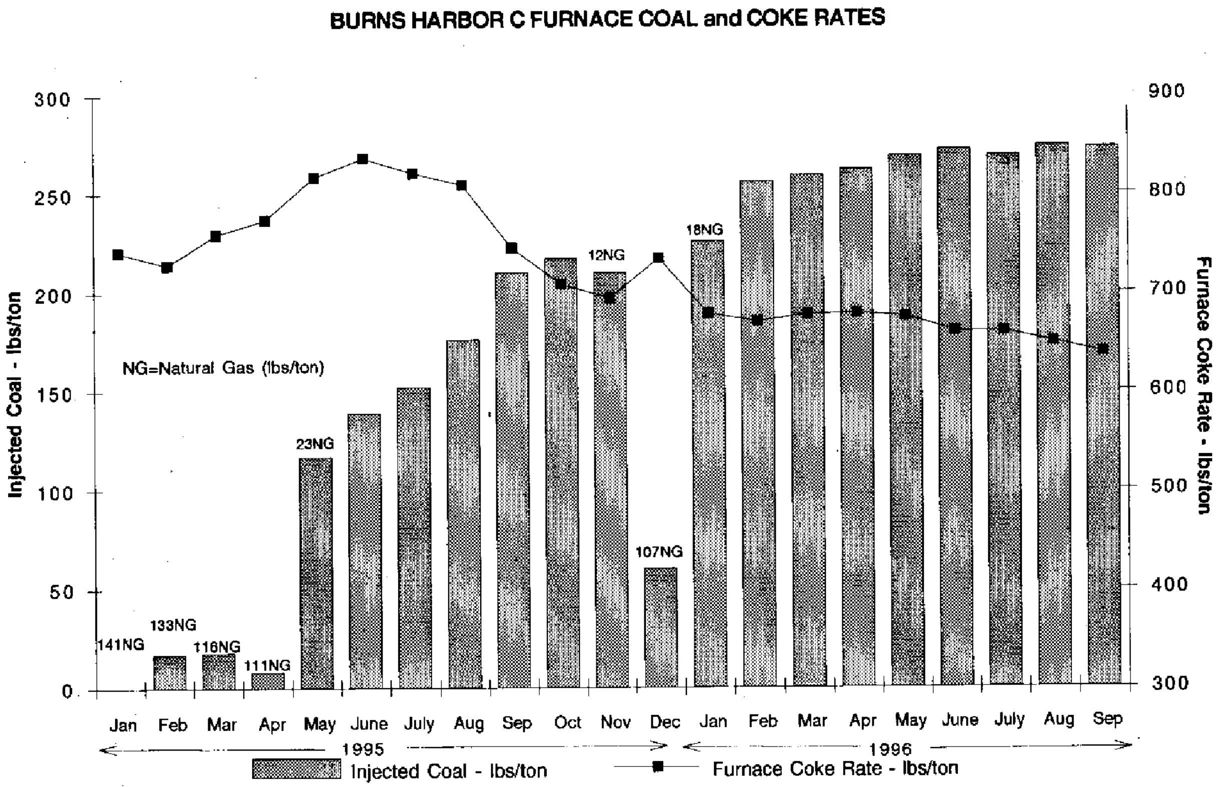


FIGURE 6

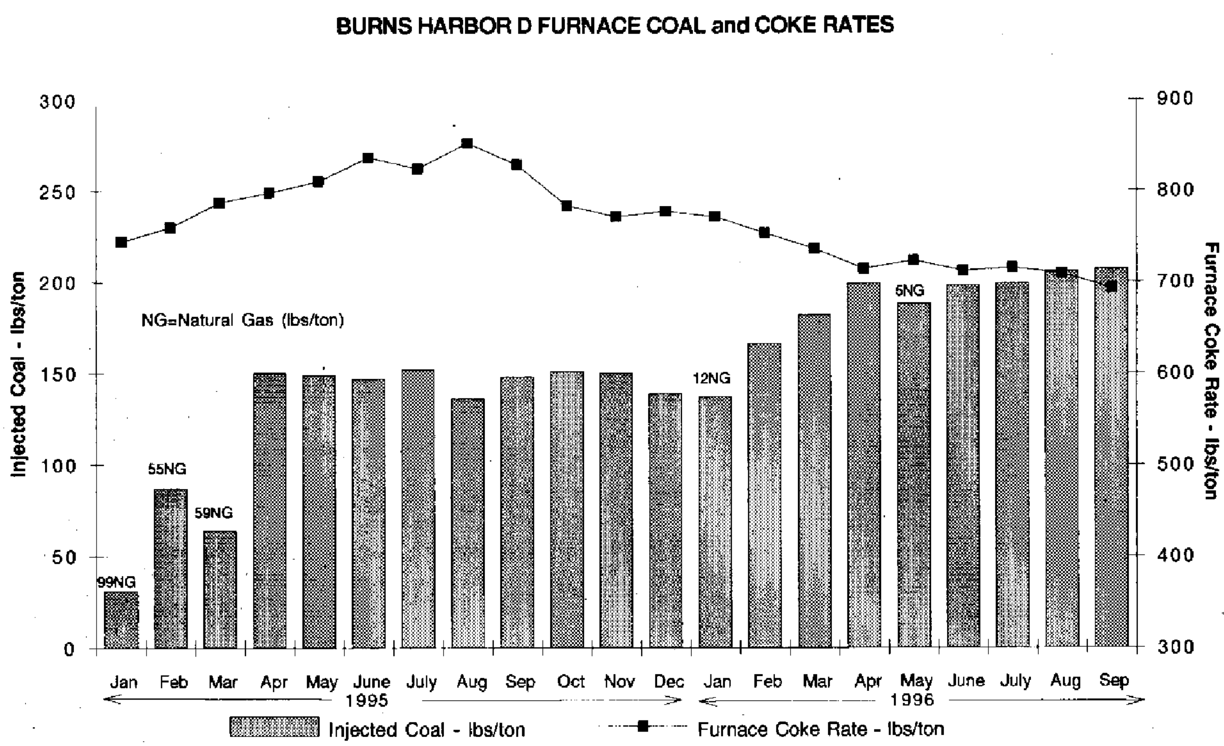
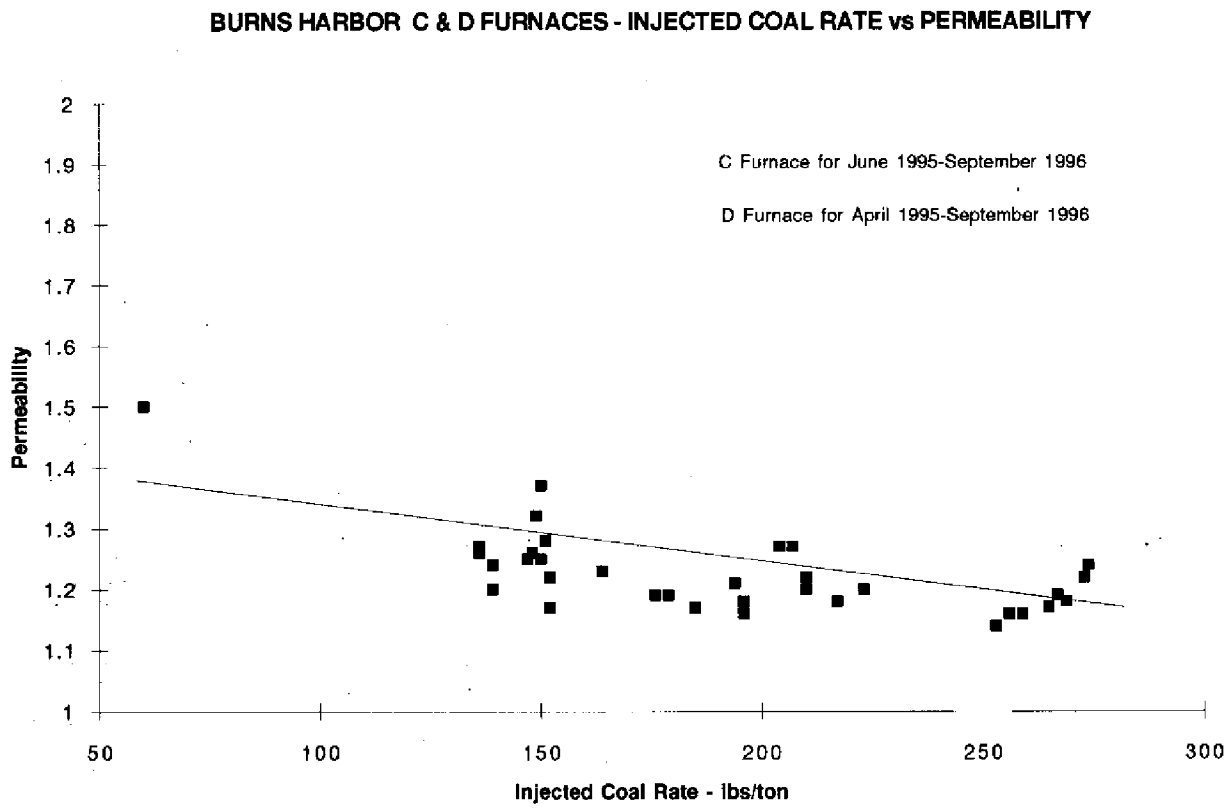


FIGURE 7


BURNS HARBOR C & D FURNACES - INJECTED COAL RATE vs PERMEABILITY
C Furnace for June 1995-September 1996
D Furnace for April 1995-September 1996
Permeability
2
1.9
1.8
1.7
1.6
1.5
1.4
1.3
1.2
1.1
1
50
100
150
200
250
300
Injected Coal Rate - lbs/ton

Another advantage of low volatile coal was a substantial reduction in electrical energy at the coal grinding facility due to the softness of the coal. The Hargrove Grindability Index of the low volatile coals is in the range of 90 to 101 compared to 46 for the high volatile coal.

Table IV also shows the recent operation of July 1996 using low volatile coal. The coal rate has increased to about 270 lbs/ton, the furnace coke rate has been reduced to 660 lbs/ton and the permeability has stabilized at 1.19. The lower blast pressure seen for the July 1996 period is also an indication of better furnace permeability. This was accomplished with increased use of blast moisture to produce more hydrogen in the bosh gas. This is shown by the increase in hydrogen content of the top gas. The increased hydrogen content results in a lower density bosh gas and, therefore, reduced gas flow resistance through the furnace stack.

Coke/Coal Replacement Ratio

The quantity of furnace coke that is replaced by an injected fuel is an important aspect of the overall value of the injectant on the blast furnace operation. A detailed analysis of the furnace coke/coal replacement ratio for the C and D furnaces at Burns Harbor has been completed.

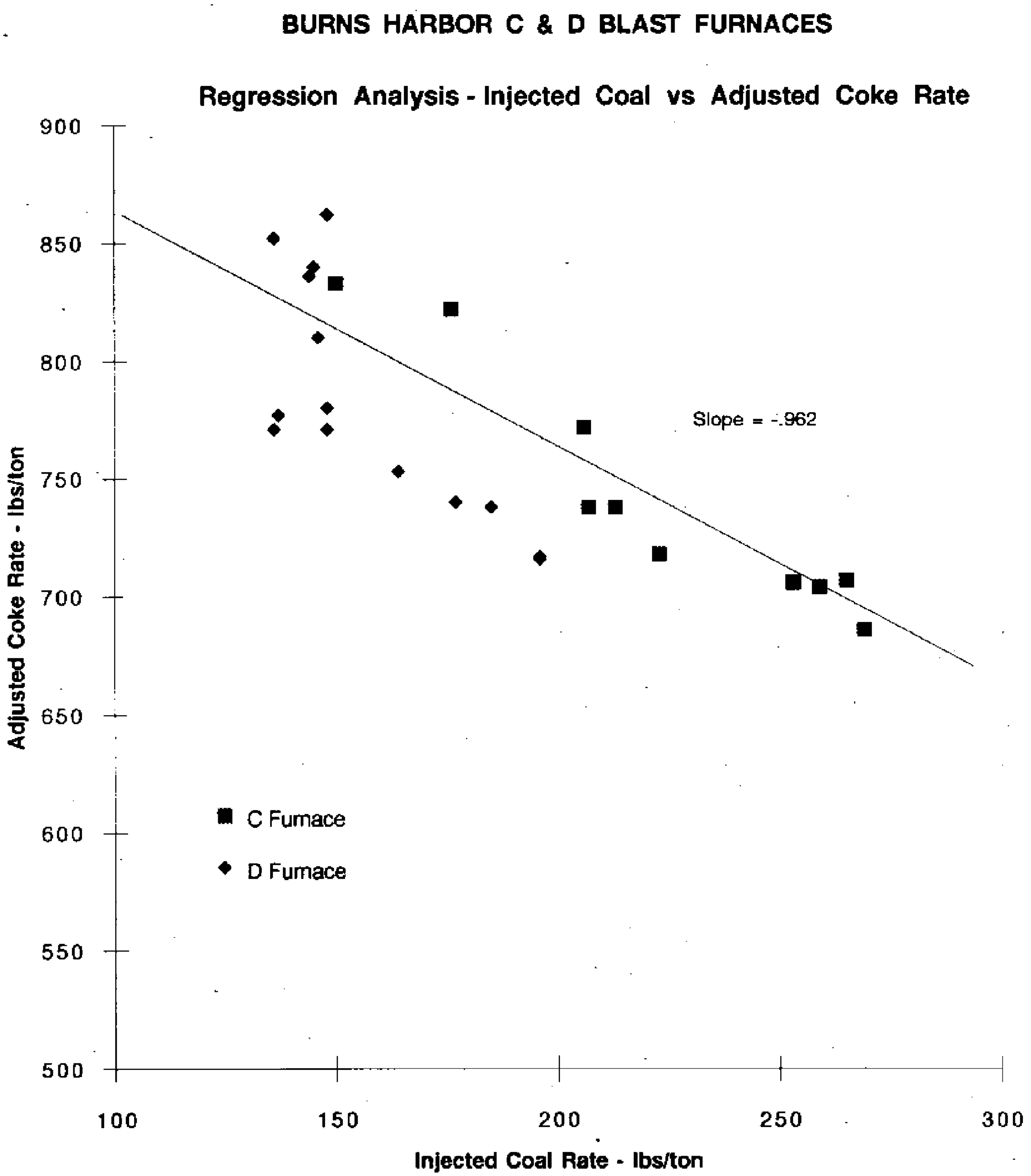
The replacement ratio for a blast furnace injected fuel is defined as the amount of coke that is replaced by one pound of the injectant. However, there are many furnace operating factors, in addition to the injectant, that affect the coke rate. In order to calculate the coke replaced by coal only, all other blast furnace operating variables that result in coke rate changes must be adjusted to some base condition. After adjusting the coke rate for changes caused by variables other than the coal, the remaining coke difference is attributed to the injected coal.

This evaluation was conducted with monthly average operating data compared to an appropriate base period for each furnace. Twenty-five months of data on both furnaces through the second quarter of 1996 were used in this evaluation.

The adjusted coke rates and the injected coal are plotted in Figure 8 along with the best fit regression line. The slope of the best fit line shows that coke/coal replacement is 0.96. This is an excellent replacement ratio and is significantly better than the 0.8-0.9 replacements reported by other coal injection operations.

The major conclusion of the test work to date is that granular coal performs very well in large blast furnaces. All other blast furnace coal injection systems use pulverized coal and some believed that pulverized coal was a requirement for large furnaces. The injection rates at Burns Harbor are not yet at the 400 lbs/ton level achieved by some, but there is nothing in the Burns Harbor experience to date that precludes higher injection rates with granular coal. The Burns Harbor furnaces will probably be limited to injection rates lower than 400 lbs/ton because of the lack of burden distribution equipment like moveable armor or a bell-less top, but this is a furnace limitation and not a coal size limitation.

FIGURE 8


BURNS HARBOR C & D BLAST FURNACES
Regression Analysis - Injected Coal vs Adjusted Coke Rate
900
850
800
750
700
650
600
550
500
Adjusted Coke Rate - lbs/ton
Slope = -.962
C Furnace
D Furnace
100
150
200
250
300
Injected Coal Rate - lbs/ton

Future Testing

The testing of different coals will continue through 1997. The first test will be with a processed sub-bituminous coal from the Encoal Corporation in Gillette, Wyoming. The Encoal operation has also been supported by the Clean Coal Technology program. About 13,000 tons of Process Derived Fuel (PDF) from Encoal will be used in the Burns Harbor furnaces for about one week.

A trial will be conducted to determine the effect of granular versus pulverized coal. The same low volatile coal that has been injected through most of 1996 with a granular size will be pulverized to 70-80% minus 200 mesh for a one month trial. This will be the first time that a direct comparison of granular versus pulverized coal will be conducted on the same blast furnace.

Additional testing to be conducted in 1997 includes a high ash content coal and a high volatile coal. The high ash content coal will be similar to the base low volatile coal in all respects except the ash. This trial will provide a unique opportunity to determine the effect of coal ash in the blast furnace process.

The test with a high volatile coal will be a direct comparison to the base low volatile coal at a high injection rate. This test along with the high ash test will provide a sound basis for economic evaluations of alternative coal sources for all U.S. blast furnace operations with coal injection.

VII. REFERENCES

1. D. S. Gathergood, "Coal Injection Into the Blast Furnace", International Iron & Steel Institute Committee on Technology, April 26, 1988.

2. D. S. Gathergood and G. Cooper, "Blast Furnace Injection - Why Granular Coal"? Steel Technology International, 1988.

3. D. Kwasnoski and L. L. Walter, "Blast Furnace Granular Coal Injection", Second Annual Clean Coal Technology Conference, Atlanta, GA, September 1993.

4. D. Kwasnoski and L. L. Walter, "Blast Furnace Granular Coal Injection", Third Annual Coal Technology Conference, Chicago, IL, September 1994.

5. L. L. Walter, R. W. Bouman and D. G. Hill, "Blast Furnace Granular Coal Injection", Fourth Annual Coal Technology Conference, Denver, CO, September 1995.

TABLE I. ESTIMATED GRANULAR COAL INJECTION PROJECT COST SUMMARY

	$ Million	
Phase I Design	5.19	
Phase II Construction and Start-Up	133.85	
Phase III Operation	51.61	
Total Cost	190.65	
Cost Sharing		
DOE	31.26	(16.4%)
Bethlehem Steel	159.39	(83.6%)
	190.65	

TABLE II

BURNS HARBOR BLAST FURNACE
RESULTS - NATURAL GAS COAL INJECTION

	D Furnace November 1994	D Furnace April 1995	C Furnace September 1995
Fuel Rate, lbs/ton			
Natural Gas	140	-	-
Coal	-	150	210
Coke	743	798	745
Blast Conditions:			
Reported Wind, MSCFM	171	174	164
Oxygen Enrichment, %	4.0	2.4	5.2
Moisture, Grs/SCF	6.0	16.0	8.5
Blast Pressure, psig	38.0	38.6	38.9
Flame Temperature, F	3685	3793	4062
Top Temperature, F	240	252	213
Hot Metal Analysis, %			
Silicon	.52	.56	.62
Sulfur	.040	.041	.035
Slag Analysis, %			
SiO_2	37.74	36.31	36.57
Al_2O_3	9.64	9.70	9.50
CaO	36.50	38.21	37.71
MgO	12.20	12.08	12.31
Sulfur	0.87	1.09	1.19
Slag Volume, lbs/ton	393	437	437
Furnace Permeability	1.52	1.50	1.30
Top Gas Analysis:			
H_2,%	7.33	3.05	3.13
BTU/SCF	92.8	82.6	88.1

TABLE III

COALS USED AT BURNS HARBOR IN 1995

Coal	Eastern Ky. High Volatile	Virginia Low Volatile	Virginia Low Volatile	W. Virginia Low Volatile	W. Virginia Low Volatile
Vol. Matter, %	36.0	18.0	19.6	16.5	18.4
Ash, %	7.50	5.30	5.16	5.75	5.50
Sulfur, %	0.63	0.80	0.75	0.58	0.77
Moisture*, %	3.0	1.5	1.5	1.5	1.4
Gross Heating Value, BTU/lb	13900	14900	15029	14550	14775
Hargrove Grindability Index	46	100	101	94	90
Ultimate Analysis, %					
C	78.0	87.0	87.0	86.0	85.3
O	7.00	1.40	1.52	2.20	3.07
H	5.4	4.4	4.2	4.2	4.0

---

* After drying and grinding

TABLE IV

BURNS HARBOR C FURNACE RESULTS WITH COAL INJECTION

	September 1995	November 1995	July 1996
Coal Type	High Volatile	Low Volatile	Low Volatile
Fuel Rate, lbs/ton			
Coal	210	210	269
Coke	745	694	660
Blast Conditions:			
Reported Wind, SCFM	164	163	154
Oxygen Enrichment, %	5.2	4.6	5.6
Moisture, Grs/SCF	8.5	7.6	16.3
Blast Pressure, psig	38.9	39.4	38.6
Flame Temperature, F	4062	3996	3949
Top Temperature, F	213	210	244
Hot Metal Analysis, %			
Silicon	.62	.45	.49
Sulfur	.035	.041	.039
Slag Analysis, %			
SiO_2	36.57	37.26	37.04
Al_2O_3	9.50	8.73	8.91
CaO	37.71	38.17	38.56
MgO	12.31	12.28	11.94
Sulfur	1.19	1.25	1.31
Slag Volume, lbs/ton	437	428	434
Furnace Permeability	1.30	1.26	1.19
Top Gas Analysis:			
H_2%	3.13	3.15	4.31
BTU/SCF	88.1	84.1	89.7

INDEX

Background 1
Introduction 1
Global Integration 2
Project Objectives 3
Project Team 4
Technology Description 4
Inherent Advantages of CPICOR 6
Feasibility of CCPG Integration 8
Demonstration Site 9
Project Schedule and Milestones 9
Commercial Outlook 10
Rationale for CPICOR Project Size 11
Conclusion 11

LIST OF FIGURES

1. Age of U.S. Coke Plants 1
2. CPICOR Conceptual Flow Diagram 1
3. Typical Gas Turbine Installation 2
4. ISCOR COREX® 2
5. AISI Direct Ironmaking 3
6. DIOS 3
7. HIsmelt 3
8. ASU Facility 3
9. Site Location 5
10. COREX® Process Flow 4
11. Reference Chart for COREX® Coals 7
12. Combined Cycle Statistics 8
13. Project Time Line 9
14. Size Distribution of Domestic Blast Furnaces 11

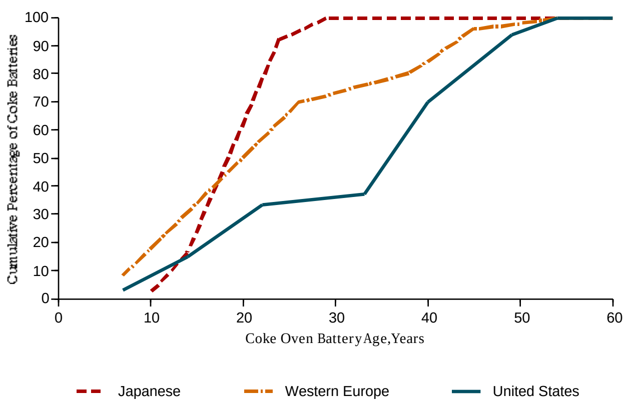
DISCLAIMER

Geneva Steel, Centerior Energy Corp., and Air Products and Chemicals, Inc. currently hold no rights in or to the COREX® process or in or to the combined cycle power generation system and expressively disclaim any warranty or guarantee with respect to the information contained herein.

BACKGROUND

A growing coke shortage is impacting the U.S. ability to produce iron and steel. Driven by environmental concerns of the sixties, the government imposed increasingly stringent requirements upon the U.S. coking industry to substantially lower the level of airborne pollutants. The U.S. steel industry, subjected to the economics of the ‘70s and ‘80s and unable to justify the building of new coke units or the environmental modifications required to save its antiquated coking batteries, purchased foreign coke (**Figure 1**). The impact of this policy in the mid ‘90s has been a rapid depletion of the world's surplus in coke production. This depletion will be further impacted as the Clean Air Act Amendments of 1990 take effect.

Age of U.S. Coke Plants FIG.1



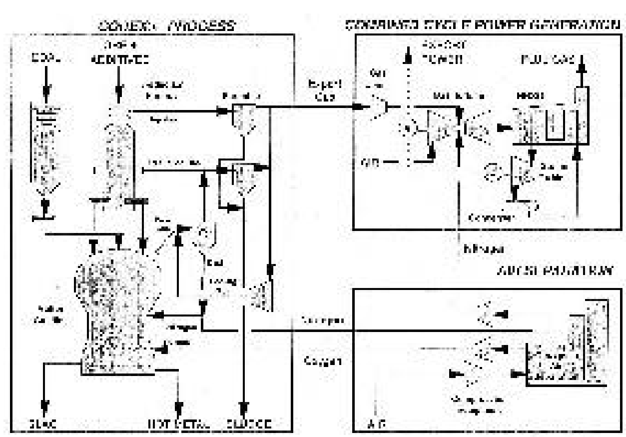
The U.S. steel industry, in order to maintain its basic iron production, is thus moving to lower coke requirements and to the cokeless or direct production of iron. The Department of Energy, in its Clean Coal Technology programs, has encouraged the move to new coal-based technology. The steel industry, in its search for alternative direct iron processes, has been limited to a single process, COREX®. The COREX® process, though offering commercial and environmental acceptance, produces a copious volume of offgas which must be effectively utilized to ensure an economical process. This volume, which normally exceeds the internal needs of a single steel company, offers a highly acceptable fuel for power generation. The utility companies seeking to offset future natural gas shortages are interested in this clean fuel.

INTRODUCTION

The COREX® smelting process, when integrated with a combined cycle power generation facility (CCPG) and a cryogenic air separation unit (ASU), is an outstanding example of a new generation of environmentally compatible and highly energy efficient "Clean Coal" technologies. This combination of highly integrated electric power and hot-metal co-production, has been designated CPICOR™. "Clean Power from Integrated Coal/Ore Reduction." A consortium of leading companies who recognized the dilemmas of the U.S. steel and utilities industries. These companies jointly proposed to the U.S. Department of Energy a collaborative effort to commercially demonstrate the simultaneous production of iron and power by utilizing the COREX® export gases with an advanced U.S. combined cycle power generation unit (**Figure 2**). CPICOR further proposed to demonstrate optimum efficiency by combining the power generation and air separation units. The proposal was accepted for negotiation under Clean Coal V utilizing a 3,200 tons per day COREX® unit.

The consortium's selection of the COREX® process was based upon several factors. The U.S. urgently requires demonstration of direct iron production on a full commercial scale. The COREX®, as demonstrated by the operating unit at ISCOR and the unit under construction at Pohang, is the only process ready for upgrading to a production capacity suitable for the U.S. The Environmental Protection Agency requires an environmentally acceptable process. The COREX® process has fully demonstrated its compliance. The domestic steel

CPICOR Conceptual Flow Diagram FIG.2



industry is seeking economic operating incentives over the present coke plant/blast furnace route. The COREX® produces a lower cost hot metal. The utilities require a clean coal gas for commercial power generation. The COREX® produces gas flow rates and calorific levels more acceptable to power generation and with lower sulfur and NOx levels than all other processes.

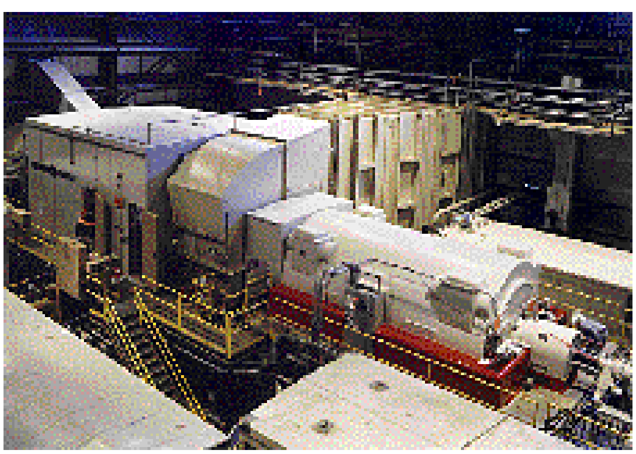
GLOBAL INTEGRATION

CPICOR is the integration of international innovations in power generation, direct ironmaking, and air separation that have reached a maturity for full scale commercialization. The U.S. Department of Energy and the major power generation equipment companies have spearheaded the development of the industrial gas turbine in the United States. From the first jet engines of the forties and through five decades of development, combined cycle power generation, using various energy sources, has developed to be the global answer for the nineties and beyond. Single combined cycle units can generate power levels to 220 megawatts (MW) with units under design for 350 MW (**Figure 3**). Coal gasification, as an energy source, has been successfully demonstrated at the Plaquemines facility in Louisiana and the Cool Water facility in California. These generation and gasification technologies will be the basis for CPICOR's high efficiency electrical power generation.

Development of direct ironmaking has been a recent challenge. Dominated by the simplicity and efficiency of the stolid blast furnace, direct ironmaking received secondary interest until the impact of environmental restrictions in the '70s and '80s. Focused specifically on coke oven emissions, environmental requirements have driven the cost of coke plants to a plateau unacceptable to U.S. and European industries. In response, the Germans and Austrians developed a direct ironmaking pilot plant in the '80s based on a concept of Korf Industries, which was eventually termed the COREX® process.[1] In the late 1980s, political pressure on South Africa resulted in the start up of the first small scale 330,000 tons per year COREX® unit (**Figure 4**). Since restarting in 1989, this plant at ISCOR has operated successfully on lump ores and non-coking coals. Encouraged by the success of the COREX® process and pressured by tightening environmental restrictions, the world's leading iron producers entered a belated race for direct ironmaking. The U.S. has under development the AISI direct ironmaking process (**Figure 5**), Japan the DIOS (**Figure 6**), Australia the HIsmelt (**Figure 7**), and Russia the ROMELT. Today, as evidenced by Korea's and India's selection of 770,000 tons per year COREX® processes, no other unit is yet ready for commercialization or offers any substantial benefit over COREX®/CPICOR for the United States.

The commercial production of oxygen in air separation units (ASU) is a well established technology (**Figure 8**). The process used for the first small 1.3 tons per day oxygen plant in the U.S. in the early 1900's was basically the same as that used in present 2,500 tons per day (TPD) installations. Over the history of the air separation industry, hundreds of commercial oxygen plants

Typical Gas Turbine Installation FIG. 3

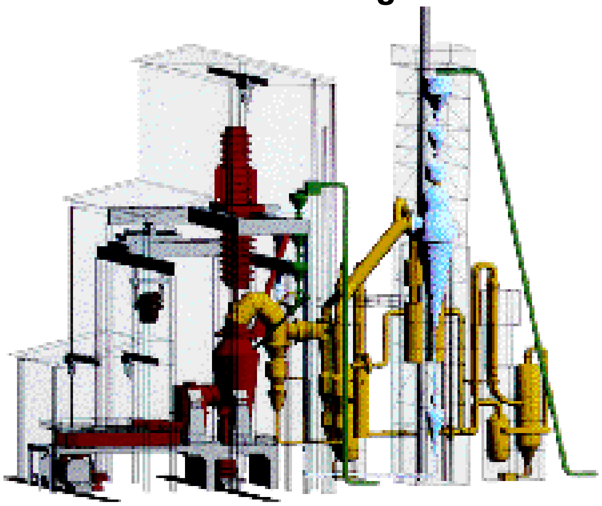


ISCOR COREX®

FIG. 4

AISI Direct Ironmaking

FIG. 5



Smelter vessel and lance

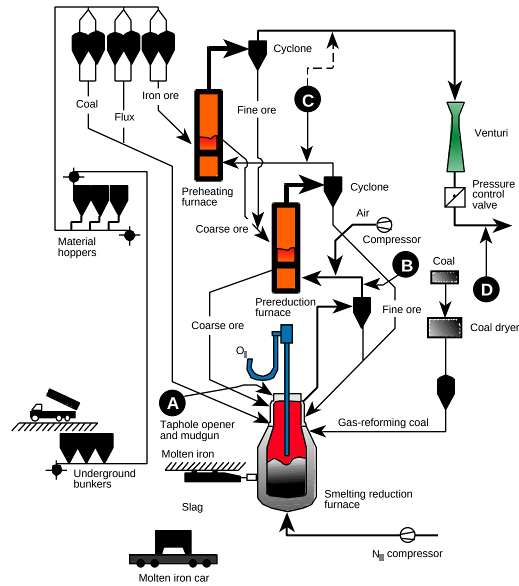
Offgas cleaning and tempering loop

Pre-reduction shaft furnace and ore feed

Coal feed system

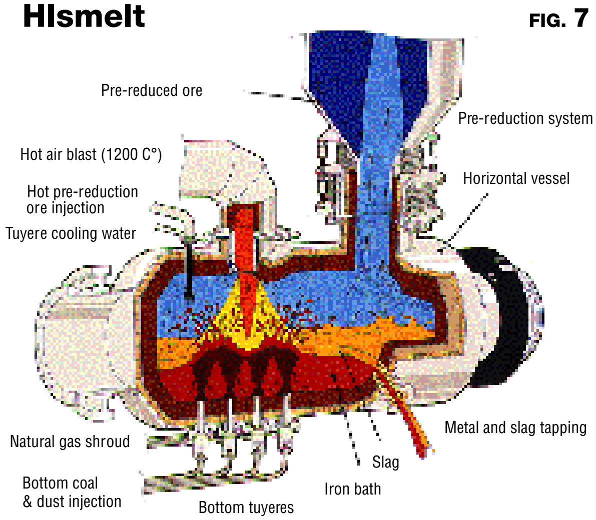
DIOS

FIG. 6



HIsmelt

FIG. 7



ASU Facility

FIG. 8

have been built, and presently more than 70,000 tons per day of oxygen capacity exists in the U.S. The ASU is proven, reliable, and highly efficient and will be integrated with the CCPG and COREX® within the CPICOR process. CPICOR will expand the U.S. coal base by including a wider range of coals for the simultaneous production of iron and power and will provide an integrated environmental solution for the economical revival of our steel, coal and power industries.

PROJECT OBJECTIVES

The project objectives are to demonstrate a scale up of the COREX® and its commercial integration with the advanced combined cycle power generation system. To date, the COREX® process has demonstrated the ability to produce 330,000 tons of hot metal per year on lump ore, with the generated gas used for inplant heating purposes. To be commercially viable in the U.S., the value of the generated gas must be optimized, such as by partial integration with power generation, and the

COREX® must be scaled up to a size compatible with modern blast furnace operation. The purpose of the CPICOR project is to demonstrate that COREX® technology can be integrated with combined cycle power generation. This is an efficient and environmentally attractive way to utilize the COREX® export gas. The 3,300 net tons per day COREX® unit selected for the CPICOR project will produce 1,160,000 tons of hot metal per year to further demonstrate a 3:1 scale-up over the existing ISCOR facility, a 3:2 scale-up over POSCO's planned Pohang facility in Korea, and a viable size for U.S. operations.

PROJECT TEAM

The project team is comprised of: Centerior Energy Corp.; Air Products and Chemicals, Inc.; and Geneva Steel. Together with their principal subcontractors, Deutsche Voest Alpine Industrialanlagenbau (DVAI) and Voest Alpine Industialanlagenbau (VAI), this team is well qualified to effectively execute all phases of the CPICOR demonstration. The CPICOR project will be managed through a joint-venture entity of the partners, CPICOR Management Company, who have executed the cooperative agreement with the DOE.

DVAI, the developer of the COREX® process, will work with Geneva Steel to design and construct CPICOR's 3,300 TPD COREX® facility. Geneva Steel will provide the infrastructure of their fully integrated steel plant in Vineyard, Utah, and consume the hot metal product (**Figure 9**). Centerior Energy will bring power generation expertise. Air Products will supply its extensive project experience and technology leadership in innovative air separation plants and power generation systems.

TECHNOLOGY DESCRIPTION

The backbone of the CPICOR project is the innovative process known as COREX® in which molten iron is produced by continuous reduction and smelting of iron ore (**Figure 10**). The most innovative feature of this process is the segregation of the iron reduction and smelting into two separate reactors. This allows direct injection of coal into the high temperature melter/gasifier which thermally cracks the coal volatiles as they are released. The process is thus independent of coke. The two reactors are:

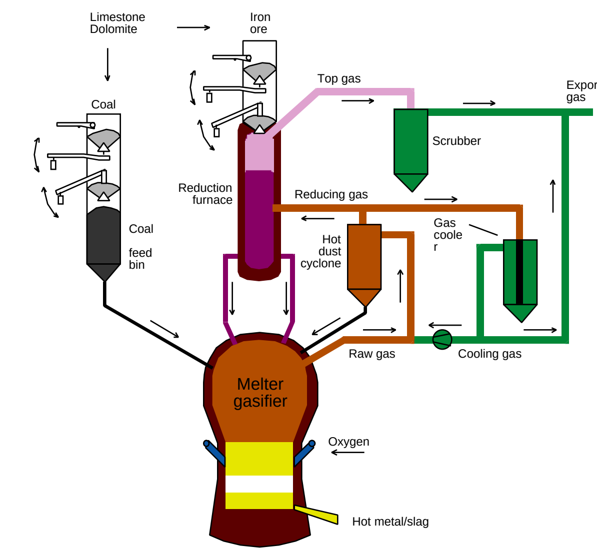
1) A **reduction shaft furnace** for reduction of lump ores, pellets, or sinter.

2) A **melter/gasifier** into which a wide variety of coals can be fed directly to produce the heat needed for smelting and to generate the reducing gases required for reducing the iron ore.

The coke oven plant with its related emissions is eliminated, and the coal gases normally required for coking can be more efficiently utilized for generating power. Hence, in addition to hot metal production, significant volumes of a clean, low-calorific value gas (175-230 BTU/SCF) are continuously generated from the COREX® process. This gas then serves as the fuel for a combined cycle power generation system.

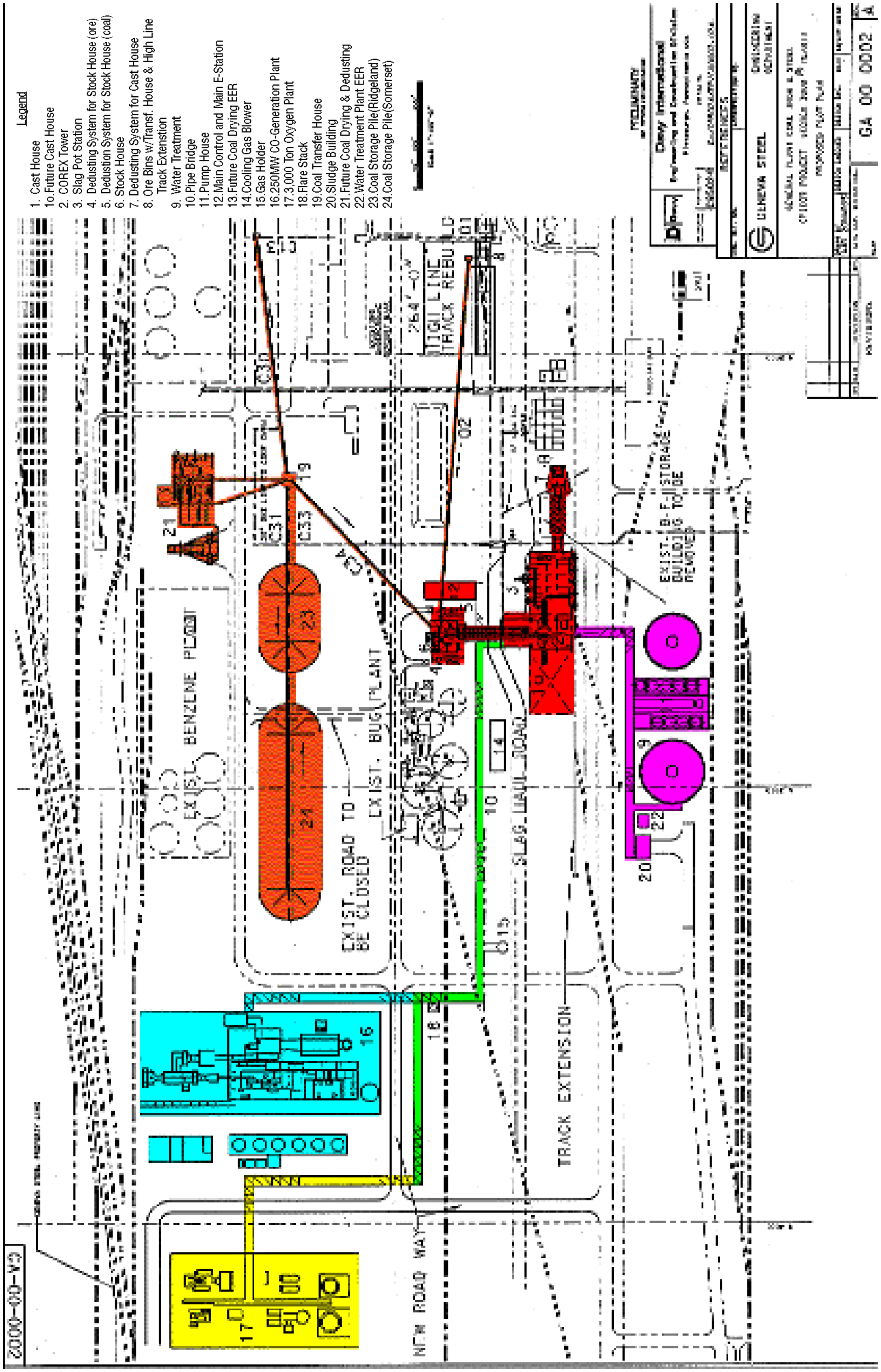
The COREX® flow diagram shows coal fed directly into the COREX® melter/gasifier. The coal, a blend of Western and Eastern coals, is devolatilized and gasified with oxygen to generate a reducing gas and sufficient heat to smelt hot metal. The process will normally use some 3,570 tons of coal and 2,700 tons of oxygen to produce 3,300 tons of hot metal per day. The high temperatures (1,800°F- 2,000°F) in the melter/gasifier result in the thermal dissociation of the coal volatiles, leaving only small amounts of

COREX® Process Flow **FIG. 10**



Site Location

FIG. 9



CH_4 in the reducing gas. The gas exits the melter/gasifier and passes through the dust separation cyclone before it is cooled to 1,550°F and transferred into the reduction shaft furnace. The reduction furnace is fed 5,180 TPD of iron ore and pellets and 953 TPD of raw fluxes. The charge is reduced or calcined by the ascending reducing gas. During the ascent, the sulfur contained in the gas reacts with the reduced iron and the calcined lime and dolomite. The reduced iron and the calcined fluxes are fed by water-cooled screws into the melter/gasifier. In the melter/gasifier, the reduced iron is melted by heat generated from the partial oxidation of the coal. The sulfur released during the smelting process is chemically captured in a calcium-rich, basic slag. The hot metal and slag are tapped periodically from the furnace hearth. The molten metal is sent directly to the steel mill for processing and the tapped slag (1,354 TPD) is recovered and used in the same manner as blast furnace slag.

The spent reducing gas (or top gas) leaves the reduction shaft essentially desulfurized and is quenched and cleaned through a series of wet scrubbers equipped with cyclonic separators. The cleaned export gas (1,790 MMBTU/hr) is delivered to the CCPG facility where it is compressed, mixed with air and nitrogen, and burned in a gas turbine/generator system. Process steam is generated in a heat recovery steam generator (HRSG) by extraction of heat from hot turbine exhaust gases and the combustion of surplus export gas. The steam produced in the HRSG drives an electric generator. This combination results in a total of 250 MW to 330 MW of generated power depending on the type of gas turbine used. Alternatively, a portion of the COREX® gas can be combusted within Geneva's plant for such processes as soaking pits, reheating furnaces, etc., with the major portion being used for combined cycle power generation. This results in 241 MW of generated electric power.

In addition to demonstrating the use of COREX® gas in a CCPG unit, another key innovative feature of the CPICOR design is the integration of the gas turbine with the ASU. A stream of air is extracted at the gas turbine axial compressor discharge to partially supply the ASU process air requirements. The ASU is designed to produce nitrogen and 3,000 TPD of high purity oxygen for the COREX® process. A portion of the nitrogen produced by the ASU is returned to the gas turbine, mixed with the compressed hot gas stream, and used to boost power output.

INHERENT ADVANTAGES OF CPICOR

CPICOR technology, by virtue of its integral co-production of hot metal and power, offers a number of distinct technical and economic advantages over the competing commercial technology. The conventional method of producing hot metal from ore and coal involves two separate processes:

1) **Cokemaking** — Coal is heated to drive off volatile matter and produce "coke" to be used as both fuel and reducing agent in a smelting operation.

2) **Blast furnace smelting** — Ore, coke, limestone, and hot air are charged to reduce and smelt the ore to produce molten iron.

Approximately 30% of the coke oven gas produced during cokemaking is used to provide heat for the cokemaking operation. The excess gas is typically sent to a utility steam boiler where it is mixed with the surplus off-gas from the blast furnace to generate power. At comparable hot metal production rates, this technology generates only about one-fifth the power produced by CPICOR technology.

Highly Efficient Use of Coal

The energy efficiency of the CPICOR technology is over 30% greater than the competing commercial technology when considering only the effective production of hot metal and electric power. The higher efficiency of the CPICOR technology is due to the more effective use of the sensible heat and volatile matter than the coke-making/blast furnace process. In addition, the CCPG achieves energy efficiencies in the 50% range compared to a maximum of 34% with conventional coal-based power systems equipped with flue gas desulfurization.

Dramatic Reduction in Emissions

CPICOR technology is less complex and environmentally superior to conventional processes. All criteria air pollutants, particularly the acid rain and PM_{10} precursors, SO_x and NO_x, are reduced by more than 85%. This reduction is due largely to the desulfurizing capability of the COREX® process, efficient control systems within the CCPG facility, and the use of oxygen in place of air in the COREX® process. The gaseous emissions from the CPICOR plant, resulting from the combustion of air and export gas in the gas turbine, are effectively controlled.

As the air toxics provisions of the Clean Air Act Amendments of 1990 take effect, the steel industry faces a serious challenge of reducing coke plant emissions. CPICOR meets this challenge because it eliminates the need for cokemaking and the associated problems of controlling fugitive emissions. The COREX® process releases no air toxics from the high temperature gasifier to the environment, and most trace elements are captured in the slag. There is no negative impact from the discharge of solids or waste waters from the CPICOR plant since all discharges are non-hazardous. The predominant solid by-product of the COREX® process is a usable slag which is very similar to blast furnace slag and can be sold as construction ballast.

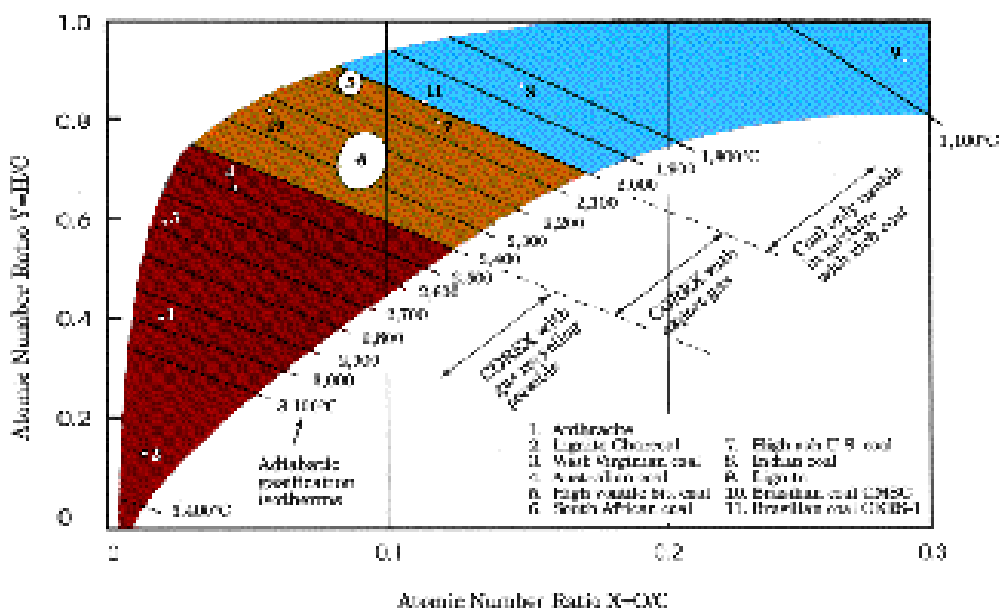
Intrinsic Desulfurization Capability

CPICOR technology has a distinct environmental advantage over conventional coal fired power generation units. Conventional coal fired units require an expensive flue gas desulfurization to clean the offgas to acceptable environmental levels. This flue gas cleanup is totally eliminated in the CPICOR process. The limestone and/or dolomite charged to the COREX® is extremely effective in scavenging the sulfur. The sulfur is removed almost totally as Ca(Mg)S with a small portion entering the iron as FeS and a fraction less than 50 ppm as H_2S or COS in the offgas.

Operational Flexibility with a Range of Coals

Unlike blast furnace technology, which requires the use of coke produced from coking coals, the COREX® process operates effectively with a wide variety of coals fed directly into the process (**Figure 11**). Since coke is produced from a narrow range of coal types with specific properties, the vast majority of the United States coal reserves cannot be utilized in conventional ironmaking. The spectrum of available coal reserves for domestic ironmaking is considerably enhanced by CPICOR. The COREX® process effectively operates over a broad range of coal qualities: volatile matter up to 35%, ash up to 25%, and sulfur up to 1.5%. Even very high sulfur coals (>1.5%) can be used effectively in the COREX® process provided they are blended appropriately with low sulfur coals.

Reference Chart for COREX® Coals **FIG. 11**



Competitive Co-Product Economics

Current commercial technology uses stand-alone process units to produce hot metal, supply industrial gases and co-produce electric power. As a result, capital costs are high, and the opportunity to integrate various process flows and heat sources among the processes is lost. In contrast, the CPICOR design is based on achieving capital, operating, and energy benefits by integrating the processes without sacrificing the flexibility for commercial operation and the reliability of power or hot metal production.

FEASIBILITY OF CCPG INTEGRATION

Although this is the first CCPG application to be fueled with COREX® export gas, the proposed design is based on proven technology. Similarly sized and larger CCPG facilities have been designed and are currently in reliable operation today with 94% to 97% availability. The steam pressure levels selected for the CPICOR design are typical of those which have been used in power generation facilities for years. The proposed gas turbine system is a proven, reliable design with a considerable number of the candidate models currently in operation. There are many heat recovery steam generator (HRSG) units of similar design and size in operating CCPG installations. Many steam turbine/electric generator sets of the type and capacity proposed for CPICOR currently exist in electric power generation facilities and have been in operation for years. All other major equipment items for the CCPG facility are likewise based on existing technology and similarly sized units (**Figure 12**).

The fueling of a CCPG system gas turbine with low-BTU gas produced by the COREX® process is unique. However, fueling gas turbines with medium and low-BTU fuel is a technology which exists commercially and is being studied, developed, and optimized by the gas turbine manufacturers. Consuming COREX® export gas in a turbine presents some technical challenges not encountered with fired boiler combustion cycles. Particulates greater than 5 microns and alkali metals can lead to turbine blade erosion. In combination with H_2S and SO_2, these materials can lead to hot metal corrosion of the combustor and inlet transition duct as well as blading of the turbine section. These potential problems are addressed by adequate scrubbing and filtration of the export gas in the CPICOR design. The use of proven and reliable wet scrubber technology will provide over 99.5% dust removal. Performance data from the ISCOR operation shows the COREX® export gas has contaminant levels generally within the gas turbine manufacturers' maximum specifications.

Combined Cycle Statistics

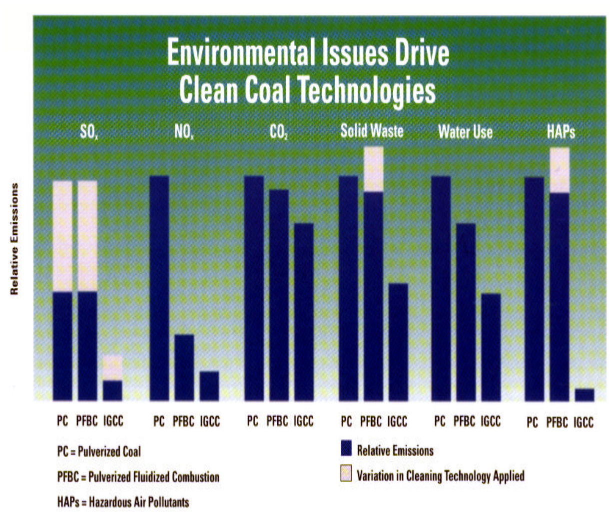
FIG. 12

Installed Combined Cycle Units

Installed Capacity (U.S.)	Over 66,000 megawatts
Operation Hours (U.S.)	Over 77 million hours
Power Range	Up to 350 MW per unit
Thermal Efficiencies	Up to 54+%
Availability	90 to 97%
Heat Rates	9000 to 6200 BTU/KWH

Coal Gasification Units

Plaquemine	two 104 MW units installed 1974
Cool Water	one 120 MW unit installed 1984
Environmental	1/10 of coal fired units



Considerable advancements have also been made in gas turbine hot section metal coatings. Cooling technologies have been developed to reduce the erosion and corrosion effects of firing offgases from processes such as COREX®. Westinghouse, Mitsubishi Heavy Industries (MHI), Siemens, ABB, General Electric, and European Gas Turbines (Ruston) all report capabilities to accept the COREX® export gas with only minor modifications to the gas turbine designs.

Operation of the gas turbine with COREX® export gas and integration with the ASU pose some unique control requirements. Nevertheless, Air Products has studied the requirements of gas turbine and ASU integration in depth and is currently demonstrating ASU-gas turbine integration, analogous to CPICOR's design, at DEMKOLEC's Integrated Gasification Combined Cycle (IGCC) facility in Buggenum, Netherlands.

DEMONSTRATION SITE

The CPICOR demonstration plant will be constructed at Geneva Steel's plant located in Vineyard, Utah. At that site, Geneva owns and operates a fully integrated steelmaking facility.

The site will take advantage of existing infrastructure to use the generated electricity at the site and transmit the surplus to the local power grid (**Figure 9**). All of the hot metal will be consumed in the steel plant. Raw materials for the demonstration plant, coal, iron ore and limestone, will be supplied by existing transportation, storage, and processing infrastructure on the site.

PROJECT SCHEDULE AND MILESTONES

The project is scheduled to commence upon the signing of the cooperative agreement with the DOE and to be completed following a multiple-phase program (**Figure 13**).

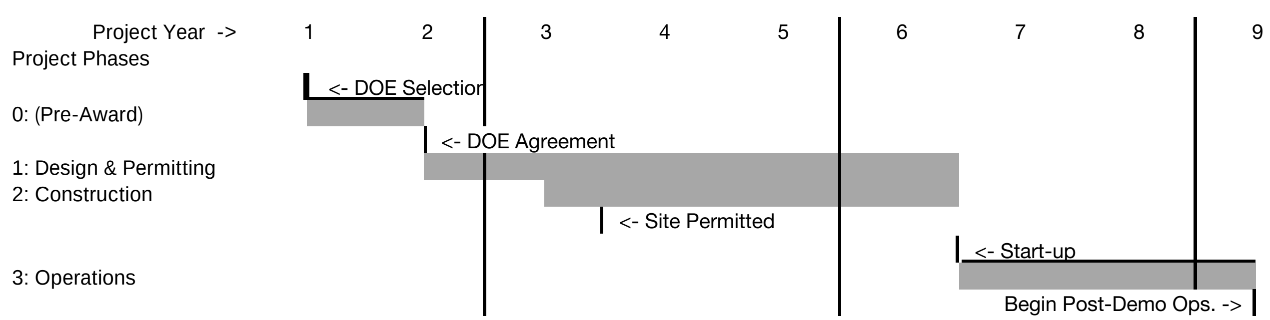
Demonstration Operating Plan

CPICOR's main objective is to demonstrate the economic, environmental, and operational aspects of a commercial-scale integrated facility and to qualify the plant using a variety of U.S. coals. CPICOR will be operated in most modes expected to be encountered in commercial applications, with the following goals:

- Establishing steady and reliable operation which compliments and enhances steel mill operations.
- Collecting performance data at various loads and conditions to assess process sensitivities, optimum conditions, and limits of sustainable operation.
- Verifying suitability of equipment and materials.
- Assessing the effect of applying new information to design and cost estimates for future commercial plants of this type.
- Testing different U.S. bituminous coals and blends to observe the effects of volatile matter, sulfur, and ash variation on performance and equipment.

To achieve these goals, a 29 month program

Project Time Line **FIG. 13**



consisting of four commercial operating periods is planned:

1. Base Coal Line-Out (4 months)
2. Steady-State Integration and Optimization (9 months)
3. Coal Quality Testing (14 months)
4. Maximum Capacity Testing (2 months)

Once the CPICOR demonstration plant is operational, it will be run as a commercial facility, producing and selling products. It will become a major source of hot metal and a net producer of electric power.

The plant will be run by the operating staffs of Geneva and Air Products. Geneva will operate the COREX® facility and will monitor all CPICOR-related systems as part of its normal steel mill functions. Air Products will operate the CCPG and ASU facilities. Each partner will supply engineering, plant staff, labor, materials, routine and major maintenance, home office support, subcontracts, and all other services needed. In addition, DVAI will provide continuous on-site support, advice, and evaluation on the technical aspects of the COREX® operation.

Post Demonstration Phase

Upon completion of the DOE program, it is anticipated that the CPICOR plant will continue to operate as a commercial facility for at least 20 years, supplying Geneva's hot metal and power.

COMMERCIAL OUTLOOK

CPICOR is intended to replace commercial coke oven/blast furnace technology in the production of hot metal for use in steelmaking. The best candidates for utilizing CPICOR technology are existing integrated steel plants with blast furnaces and coke ovens nearing the end of their useful lives and located where the local electric utility requires additional capacity. While commercialization of the COREX® process is driven primarily by the need for an environmentally sound source of hot metal for the steel industry, the production of electric power from the COREX® export gas is key to the economic competitiveness of the technology. Thus, commercialization will be facilitated by the ability of this project to obtain an attractive price for the power created by the plant.

Conventional coke oven/blast furnace technology is too expensive to be utilized as replacement units or to expand domestic ironmaking capacity. Recent studies [2, 3, 4] conclude that no new coke batteries will be built in the United States. Of the existing 79 coke oven batteries, 40 are thirty years of age or older and are due for either replacement or major rebuilds.

As a consequence of the Clean Air Act Amendments of 1990, the emissions from existing coke ovens must be reduced substantially over the next several years. It has been estimated that the total capital investment for rebuilding or replacing current capacity could be in the range of $4 to $6 billion. The capital cost of coke ovens is about $166 per ton of equivalent hot metal capacity. Coupled to the cost of a blast furnace rebuild at $155 per ton equivalent hot metal capacity, the investment in a new COREX® facility at approximately $255 per ton compares favorably on a capital basis.

If the iron and steel industry is to continue to produce liquid iron in the form of hot metal, a new technology must be developed and installed. Future competition to COREX® is likely to come from the new direct ironmaking processes being developed in both Japan (the DIOS process, **Figure 5**) and in the U.S. (the AISI process, **Figure 6**). Both of these processes produce iron and a lower calorific value export gas directly from iron ore and coal. However, the development of the COREX® technology is 8 to 12 years ahead of these other processes. Consequently, COREX®/CPICOR should become the technology of choice as domestic ironmaking capacity declines due to severe limitations in global coke supply.

RATIONALE FOR CPICOR PROJECT SIZE

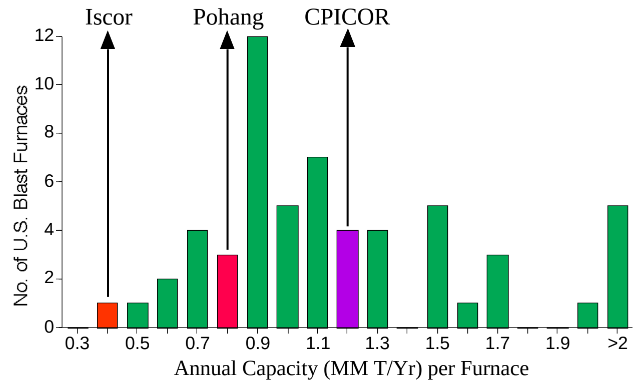
In the U.S., there are currently about 60 blast furnaces, all of which have been operating for more than ten years, with some originally installed up to 90 years ago. **Figure 14** shows the size distribution of these furnaces. As can be seen, the largest operating COREX® facility (~330,000 TPY) is only large enough to replace the smallest of these 60 blast furnaces. The construction of a new facility by POSCO for its Pohang, Korea works will increase demonstrated facility size to 650,000 to 800,000 TPY. The output of this facility is only sufficient to replace about 15% of existing blast furnaces. The proposed demonstration facility size (~1,200,000 TPY) is key to rapid commercialization of COREX®, since it will have the equivalent production rate of a 26 to 28 foot diameter blast furnace. The 3,300 TPD production will be greater than the individual production rates of 75% of domestic blast furnaces. Further scale-up from the demonstration facility by a factor of only 1.5 will produce a unit large enough to exceed the individual output of 90% of existing blast furnaces. Such a factor is well within the range of engineering feasibility. Worldwide, more than 300 blast furnaces with capacity between 0.3 and 1.2 million net tons per year could be replaced in the foreseeable future by COREX®.

CONCLUSION

As evident by the selection of the project by the DOE under Clean Coal V, the CPICOR project has strong support. This technology will provide substantial benefits to the United States coal, steel and power industries while satisfying the key objectives of the Clean Air Act and the National Energy Strategy.

Size Distribution of Domestic Blast Furnaces

FIG. 14



REFERENCES

1. "COREX®, From 200 tonnes/day to 3000 tonnes/day," AISE Annual Convention and Iron and Steel Exposition, Pittsburgh, Pa (Sept. 1993).

2. IISI Committee on Raw Materials, Brussels (1985).

3. "Coke Oven Round-up", *Metal Processing, 33* (May 1991).

4. *Ironmaking and Steelmaking,* vol. 19, No. 5 (1992).

Role Of The
Liquids From Coal Process
In The World Energy Picture

James P. Frederick (jfrederick@VCN.com, 307-686-5493)
Brent A. Knottnerus (bknottnerus@VCN.com, 307-686-5486)
ENCOAL Corporation
P. O. Box 3038
Gillette, WY 82717

ABSTRACT

ENCOAL Corporation, a wholly owned indirect subsidiary of Zeigler Coal Holding Company, has essentially completed the demonstration phase of a 1,000 Tons per day (TPD) Liquids From Coal (LFC™) plant near Gillette, Wyoming. The plant has been in operation for 4½ years and has delivered 15 unit trains of Process Derived Fuel (PDF™), the low-sulfur, high-Btu solid product to five major utilities. Recent test burns have indicated that PDF™ can offer the following benifits to utility customers:

- Lower sulfur emissions
- Lower NO_x emissions
- Lower utilized fuel costs to power plants
- Long term stable fuel supply

More than three million gallons of Coal Derived Liquid (CDL™) have also been delivered to seven industrial fuel users and one steel mill blast furnace. Additionally, laboratory characteristics of CDL™ and process development efforts have indicated that CDL™ can be readily upgraded into higher value chemical feedstocks and transportation fuels.

Commercialization of the LFC™ is also progressing. Permit work for a large scale commercial ENCOAL® plant in Wyoming is now underway and domestic and international commercialization activity is in progress by TEK-KOL, a general partnership between SGI International and a Zeigler subsidiary.

The Project[1], which was cost shared by the U.S. Department of Energy under Round Three of the Clean Coal Technology program, achieved its remaining long-term objectives in the past year. These included delivery and testing of pure PDF™ in a major Eastern U.S. bituminous coal

boiler, operation of the plant for long periods at greater than 90% availability and processing of an alternate source coal. Plans are to continue operation of the ENCOAL® plant for several purposes:

- testing the viability of alternate commercial scale equipment
- delivery of additional test burn quantities of products
- training operators for the commercial plant
- providing additional design data for the commercial plant

A no-cost extension to the Cooperative Agreement has been approved for six months to complete the required project close-out reports. This paper covers the historical background of the Project, describes the LFC™ process and describes the worldwide outlook for commercialization.

---

[1] Contract No. DE-FC21-90MC27339, ENCOAL Corporation, P. O. Box 3038, Gillette, WY 82717; Telefax (307) 682-7938

Acknowledgements

ENCOAL Corporation wishes to acknowledge the participation of D.O.E.'s project manager, Mr. Douglas M. Jewell, whose guidance and technical advice contributed to the success of the ENCOAL® project during the design, construction and operation activities over the past six years.

BACKGROUND INFORMATION

Objectives

Beneficiation of low sulfur Powder River Basin (PRB) subituminous coal is being demonstrated by the ENCOAL® Mild Coal Gasification Project using the LFC™ process. The LFC™ Technology employs a mild gasification process, that is mild pyrolysis at relatively low temperatures, to produce both liquid and solid fuels with environmentally superior properties. The demonstration plant has been in the testing and operations mode for more than 4½ years and has completed all of its original long-term goals.

ENCOAL's overall objective for the Project is to further the development of full sized commercial plants using the LFC™ Technology. In support of this overall objective, the following goals were established:

- Provide sufficient products for full-scale test burns
- Develop data for the design of future commercial plants
- Demonstrate plant and process performance
- Provide capital and operating cost data
- Support future LFC™ Technology licensing efforts

Significant progress has been made on the first four goals, and the commercialization and technology licensing efforts are in progress. This paper highlights several areas of immediate interest to potential customers and licensees. These include the status of the ENCOAL® Project, plant operating experience, plant reliability, product properties, technology development and remaining challenges. Most importantly, the status of the commercialization of the LFC™ Technology is reviewed.

General Description

ENCOAL® Corporation is a wholly owned subsidiary of Bluegrass Coal Development Company, (formerly named SMC Mining Company), which in turn is a subsidiary of Zeigler Coal Holding Company. ENCOAL® has entered into a Cooperative Agreement with the United States Department of Energy (DOE) as a participant in Round III of the Clean Coal Technology

Program. Under this agreement, the DOE has shared 50% of the cost of the ENCOAL® Mild Coal Gasification Project. The Cooperative Agreement was extended in October 1994 for an additional $18,100,000 bringing the Project total to $90,600,000 through September 17, 1996. A no-cost extension in September 1996 moved the Cooperative Agreement end date to March 17, 1997 to allow for completion of final reporting requirements. A license for the use of LFC™ Technology has been issued to ENCOAL® from the technology owner, TEK-KOL, a general partnership between SGI International of La Jolla, California and a subsidiary of Zeigler Coal Holding Company.

The ENCOAL® Project encompasses the design, construction and operation of a 1,000 TPD commercial demonstration plant and all required support facilities. The Project is located near Gillette, Wyoming at Triton Coal Company's Buckskin Mine. Existing roads, railroad, storage silos and coal handling facilities at the mine significantly reduced the need for new facilities for the Project.

A substantial amount of pilot plant testing of the LFC™ process and laboratory testing of PDF™ and CDL™ was done.[1] The pilot plant tests showed that the process was viable, predictable and controllable and could produce PDF™ and CDL™ to desired specifications. Key dates and activities in bringing the project from the pilot plant stage to its current status are:

- Through early 1987: Development of the LFC™ process by SGI.
- Mid 1987: SMC Mining Company (SMC) joined with SGI on further development.
- Mid 1988: Feasibility studies, preliminary design, economics and some detailed design work by SMC.
- June 1988: Submittal of an application to the State of Wyoming for a permit to construct the plant - Approved July 1989.
- August 1989: ENCOAL® Project submitted to the DOE as part of Round III of the Clean Coal Technology Program - Selected in December 1989.
- September 1990: Cooperative Agreement signed. Contract awarded to The M. W. Kellogg Company for engineering, procurement and construction.
- October 1990: Ground breaking at the Buckskin Mine site.
- April 1992: Mechanical completion - commissioning begun.
- June 1992: First 24 hour run in which PDF™ and CDL™ were produced.
- November 1992: SMC Mining Company and its subsidiaries, including ENCOAL®, acquired by Zeigler.
- April 1993: ENCOAL® achieves two week continuous run.
- June 1993: Plant shut down for major modifications.
- December 1993: Plant recommissioned with added deactivation loop.
- July 1994: Completed 68 day continuous run - plant operational.
- September 1994: First unit train containing PDF™ shipped and burned

successfully.

- October 1994: Two year extension and additional funding approved by DOE.
- April 1996: Shipped first unit train containing 100% PDF™.
- May 1996: Sucessfully burned PDF™ in a fully instrumented major U.S. utility boiler.

Although designed for 1000 TPD feed, the plant is currently processing 500 TPD of subituminous PRB coal due to capacity limitations in the deactivation loop. The plant produces 250 TPD of PDF™, which has the high heat content of Eastern coals but with low sulfur content, and 250 barrels/day of CDL™, which is a low sulfur industrial fuel oil. While CDL™ is different from petroleum derived oils in its aromatic hydrocarbon, nitrogen and oxygen content, it has a low viscosity at operating temperatures and is comparable in flash point and heat content.

Not a pilot plant or a "throw-away", ENCOAL's processing plant is designed to commercial standards for a life of at least 10 years. It uses commercially available equipment as much as possible, state-of-the-art computer control systems, BACT for all environmental controls to minimize releases and a simplified flowsheet to make only two products matched to existing markets. The intent is to demonstrate the core process and not make the project overly complicated or expensive.

The ENCOAL® Project has demonstrated for the first time the integrated operation of several unique process steps:

- Coal drying on a rotary grate using convective heating
- Coal devolatilization on a rotary grate using convective heating
- Hot particulate removal with cyclones
- Integral solids cooling and deactivation
- Combustors operating on low Btu gas from internal streams
- Solids stabilization for storage and shipment
- Computer control and optimization of a mild coal gasification process
- Dust suppressant on PDF™ solids

Utility test burns have shown that the fuel products can be used economically in commercial boilers and furnaces to reduce sulfur emissions significantly at utility and industrial facilities currently burning high sulfur bituminous coal or fuel oils. Ultimately, installation of commercial scale LFC™ plants should help reduce U.S. dependence on imports of foreign oil.

Process Description

Figure 1 is a simplified flow diagram of ENCOAL's application of the LFC™ Technology. The process involves heating coal under carefully controlled conditions. Nominal 3" x 0" run-of-mine

(ROM) coal is conveyed from the existing Buckskin Mine to a storage silo. The coal from this silo is screened to remove oversize and undersize materials. The 2" x 1/8" sized coal is fed into a rotary grate dryer where it is heated by a hot gas stream. The residence time and temperature of the inlet gas have been selected to reduce the moisture content of the coal without initiating chemical changes. The solid bulk temperature is controlled so that no significant amounts of methane, carbon monoxide or carbon dioxide are released from the coal.

The solids from the dryer are then fed to the pyrolyzer where the temperature is further raised to about $1{,}000^{\circ}$F on another rotary grate by a hot recycle gas stream. The rate of heating of the solids and their residence time are carefully controlled, because these parameters affect the properties of both solid and liquid products. During processing in the pyrolyzer, all remaining water is removed, and a chemical reaction occurs that results in the release of volatile gaseous material. Solids exiting the pyrolyzer are quickly quenched to stop the pyrolysis reaction, then transferred to a small surge bin that feeds the vibrating fluidized bed (VFB) deactivation unit.

In the VFB unit, the partially cooled, pyrolyzed solids contact a gas stream containing a controlled amount of oxygen. Termed "oxidative deactivation," a reaction occurs at active surface sites in the particles reducing the tendency for spontaneous ignition. The heat generated by this reaction is absorbed by a fluidizing gas stream which is circulated through a cyclone to remove entrained solids and a heat exchanger before being returned by a blower to the VFB. Oxygen content in the loop is maintained by introducing the proper amount of air through a control valve. Excess gas in the loop is purged to the dryer combustor for incineration.

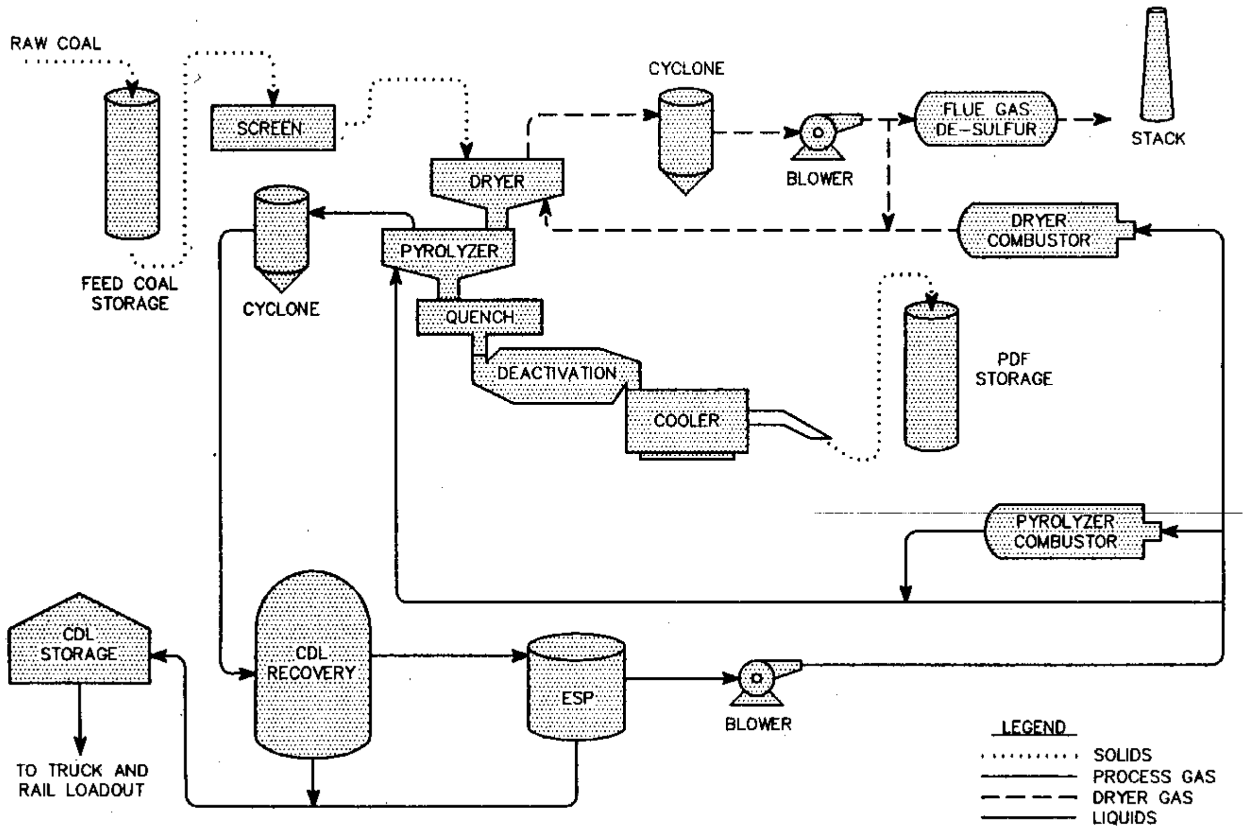


FIG. 1 : SIMPLIFIED PROCESS FLOW DIAGRAM

Following the VFB, the solids are cooled to near atmospheric temperature in an indirect rotary cooler. A controlled amount of water is added in the rotary cooler to rehydrate the PDF™ to near its ASTM equilibrium moisture content. This is also an important step in the stabilization of the PDF™. The cooled PDF™ is then transferred to a storage bin. Because the solids have little or no free surface moisture and, therefore, are likely to be dusty, a patented dust suppressant is added as PDF™ leaves the product surge bin. Patents are pending on both the oxidative deactivation andrehydration steps.

At the present time, the PDF™ is not completely stabilized with respect to oxygen and water upon leaving the plant. The PDF™ must be "finished" by a short exposure to atmospheric conditions in a layered stockpile prior to being reclaimed and shipped. In addition to atmospheric stabilized PDF™, a stable product can be made by blending run-of-plant PDF™ with either ROM coal or the atmosphere stabilized PDF™ , but there is a Btu penalty. ENCOAL® has recently completed pilot-scale equipment tests that successfully perform this finishing step using process equipment. The design uses commercially available equipment to be installed just downstream of rotary cooler mentioned above, and will effectively stabilize PDF™ on a continuous basis. Installation of this equipment is currently scheduled in 1997.

The hot gas produced in the pyrolyzer is sent through a cyclone for removal of the particulates and then cooled in a quench column to stop any additional pyrolysis reactions and to condense the desired liquids. Only the CDL™ is condensed in this step; the condensation of water is avoided. Electrostatic precipitators recover any remaining liquid droplets and mists from the gas leaving the condensation unit.

Almost half of the residual gas from the liquid recovery unit is recycled directly to the pyrolyzer, while some is first burned in the pyrolyzer combustor before being blended with the recycled gas to provide heat for the mild gasification reaction. The remaining gas is burned in the dryer combustor, which converts sulfur compounds to sulfur oxides. Nitrogen oxide emissions are controlled via appropriate design of the combustor. The hot flue gas from the dryer combustor is blended with the recycled gas from the dryer to provide the heat and gas flow necessary for drying.

The unrecycled portion of the off-gas from the dryer is treated in a wet gas scrubber and a horizontal scrubber, both using a water-based sodium carbonate solution. The wet gas scrubber recovers the fine particulates that escape the dryer cyclone, and the horizontal scrubber removes most of the sulfur oxides from the flue gas. The treated gas is vented to a stack. The spent solution is discharged into a pond for evaporation. The plant has several utility systems supporting its operation. These include nitrogen, steam, natural gas, compressed air, bulk sodium carbonate and a glycol/water heating and cooling system. Figure 2 is a plot plan for the ENCOAL® Plant facilities including the Buckskin Mine rail loop that is used for shipping products.

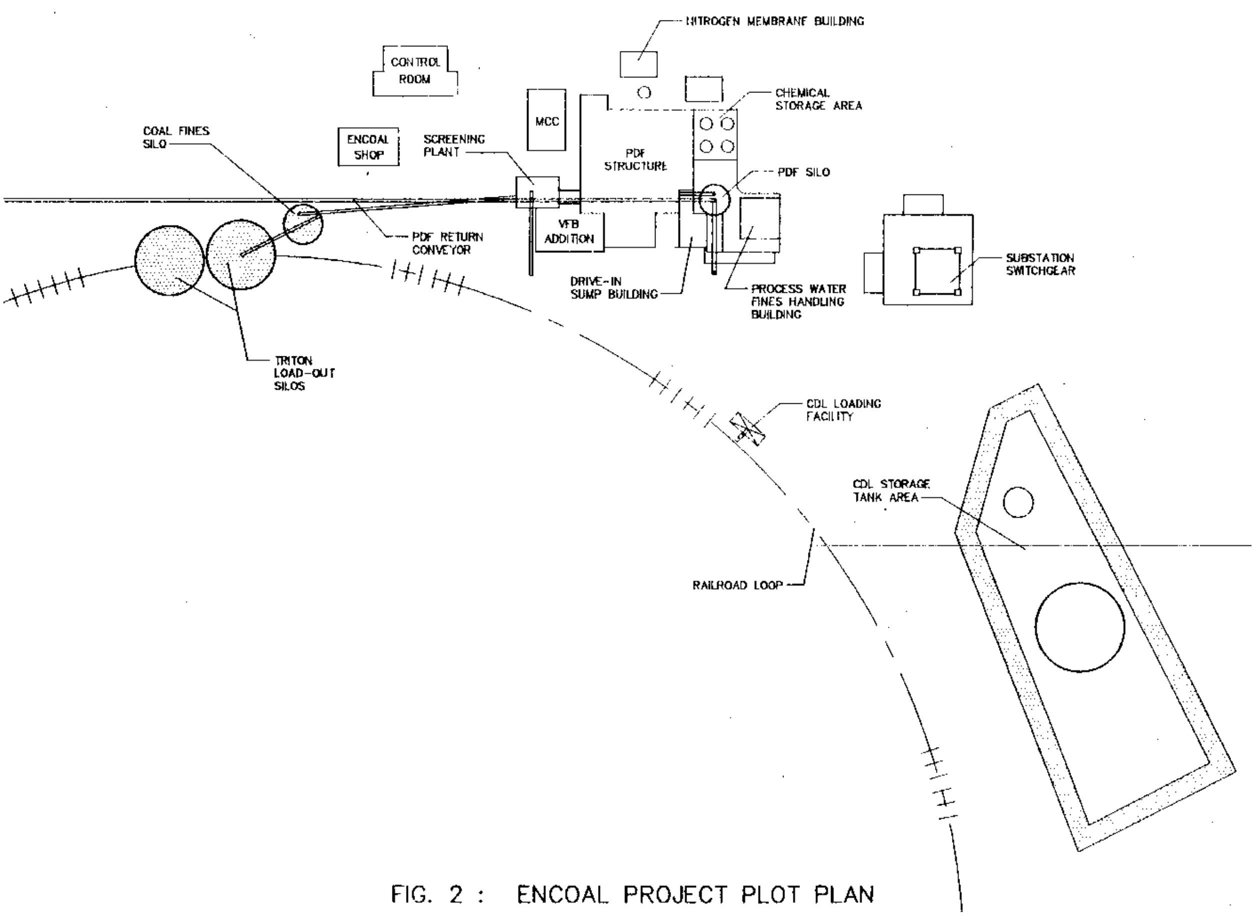


FIG. 2 : ENCOAL PROJECT PLOT PLAN

PLANT OPERATING EXPERIENCE

Production History

ENCOAL's LFC™ plant and facilities have now operated in an integrated mode producing PDF™ and CDL™ for more than 12,000 hours. The major pieces of equipment, including the large blowers, combustors, dryers, pyrolyzer and cooler have operated fare more hours overall considering hot standby and ramping operations. This equipment has been demonstrated to operate reliably. Steady state operation exceeding 90% availability has been achieved for extended periods for the entire plant, albeit at 50% of plant capacity, and the plant is currently operational. Although some testing is still ongoing, all of the plant production of PDF™ and CDL™ is for test burns. Table1 summarizes the plant operations over the last 4½ years.

	1992	1993	1994	1995	1996*
Raw Coal Feed (Tons)	5,200	12,400	67,500	65,800	59,500
PDF™ Produced (Tons)	2,200	4,900	31,700	28,600	30,500
PDF™ Sold (Tons)	-0-	-0-	23,700	19,100	32,700
CDL™ Produced (Bbl)	2,600	6,600	28,000	31,700	27,500
Hours on Line	314	980	4,300	3,400	3,200
Average Length of Runs	2.2	8.2	25.9	38.0	N/A**

***	Through November 15, 1996**
****	Not Applicable; Plant in operation.**

Table 1. ENCOAL® Plant Performance

Product recoveries from the feed coal have varied somewhat from the original projections. In the case of PDF™, recovery has been slightly lower. This is because more fines are generated in the process than expected and they are not all currently recovered. CDL™ recovery is higher than expected by 10-15%, apparently due to a more efficient liquid recovery system than the one used in the pilot plant.

Product Test Burns

Commercialization of both the solid (PDF™) and liquid (CDL™) products from the ENCOAL® Plant took a major step forward in 1994. PDF™ was shipped in trainload quantities for the first time to utility customers. The results of these shipments demonstrated that utility and industrial users can plan for test burns of PDF™ with confidence. Use of CDL™ in the industrial low sulfur residual fuel oil market was also demonstrated.

In September 1994, ENCOAL® commenced shipment of PDF™ to utility customers via the Burlington Northern railroad. Shipments made to the first customer, the Western Farmers Electric Cooperative in Hugo, Oklahoma, started at a 15% blend level and ranged up to 30%. The upper level of these blends was determined by the heat content limit in the customer's boiler. Shipments to a second customer, Muscatine Power and Water in Muscatine, Iowa, started at 40% PDF™ and ranged up to 91%. The rail cars in this shipment were capped with a small amount of ROM Buckskin coal. Capping is one way to control loss of fine material during shipment. Because the ROM coal becomes blended with the PDF™ upon unloading, it ends up as a 91% blend.

With these first shipments, ENCOAL's goals were to demonstrate its ability to coordinate with the Buckskin Mine in loading and shipping consistent blends, to ship PDF™ with dust generation comparable to or less than ROM Buckskin coal, and to ship PDF™ blends that are stable with respect to self heating. Furthermore, ENCOAL® intended to demonstrate that PDF™ could be transported and delivered to customers using regular commercial equipment. With respect to utilization, the goal for these shipments was for customers to burn trial amounts (½ unit train minimum) of PDF™ blends with minimal adjustment of equipment. These goals have all been met as reported in a more detailed test burn report[2].

In 1995, ENCOAL® shipped two additional trains to Muscatine and initiated shipments to a third customer, Omaha Public Power District (OPPD) in Omaha, Nebraska. Three unit trains were shipped to OPPD containing approximately 25% PDF™ . This customer has been burning PRB coal in a boiler designed for bituminous coal for some time, and the increased heat content of the PDF™ blends helped increase plant output.

In 1996, ENCOAL® began shipping unit trains containing 100% PDF™ for the first time. As of the end of October 1996, two 100% PDF™ unit trains have been delivered to two separate utilities for test burns. The first was burned in Indiana-Kentucky Electric Cooperative's (IKEC) Clifty Creek Station, which is jointly owned by American Electric Power (AEP). The PDF™ was blended with Ohio high sulfur coal at the utility and burned in the Babcock & Wilcox open-path, slag-tap boiler with full instrumentation. Blends tested ranged between 70 and 90% PDF™, and burn results indicated that even with one pulverizer out of service, the unit capacity was increased significantly relative to the base blend. More importantly, there was at least a 20% NO_x reduction due to a more stable flame. Completion of this test burn achieved a major DOE Cooperative Agreement Milestone of testing PDF™ at a major U.S. utility. This goal is discussed further in an independent third party test burn report.[6] The remaining 100% PDF™ unit train was sent to Union Electric near St. Louis, MO. PDF™ shipments through October 1996 are documented in

Table 2.

Coincident with PDF™ shipments was a broadening of the customer base for the liquid CDL™ product. To date, ENCOAL® has shipped CDL™ to eight different customers. With the exception of one steel mill injectant test, the CDL™ has been blended and used as fuel oil. CDL™ has proven to be acceptable in the fuel oil market through these test burns.[2] However, since the price of fuel oil is currently very low, upgrading of CDL™ into more profitable products has been studied. Initial testing of CDL™ has shown that extraction of higher value products is both technically and economically feasible. Detailed characterization of the CDL™ and evaluation of several upgrading processes have already been completed. Other processes continue to be studied, but in general, upgrading of CDL™ will yield specialty chemical feedstocks and transportation fuels. Further work on upgrading is planned in 1997. Table 3 summarizes the CDL™ tank car shipments thus far.

DATE LOADED	CUSTOMER	BLEND (%PDF™)	TONS SHIPPED			HEAT CONTENT (Btu/lb)
			PDF™	COAL	BLEND	
09/17/94	W. Farmers	14.4	922	5,448	6,370	8,760
09/24/94	W. Farmers	21.2	1,080	4,020	5,100	8,910
10/01/94	W. Farmers	25.1	1,508	4,493	6,001	8,940
10/10/94	W. Farmers	31.9	1,603	3,241	5,024	9,310
10/24/94	W. Farmers	24.0	2,665	8,426	11,091	9,060
11/23/94	Muscatine	39.0	1,957	3,122	5,079	9,630
11/29/94	Muscatine	66.6	3,423	1,713	5,136	9,670
12/13/94	Muscatine	90.7	10,576	1,082	11,658	10,000
04/23/95	Muscatine	33.0	3,979	8,094	12,073	9,127
05/05/95	Omaha PPD	24.4	2,711	8,412	11,123	8,940
05/11/95	Omaha PPD	24.0	2,669	8,464	11,133	8,939
05/13/95	Omaha PPD	26.0	2,952	8,398	11,350	8,854
08/16/95	Muscatine	94.0	6,750	434	7,184	9,873
04/25/96	IKEC (AEP)	100.0	9,739	0	9,739	10,682
07/22/96	Union Electric	100.0	11,260	0	11,260	10,450

Table 2. Summary of Trains Shipped Containing PDF™ *(Through 10/31/96)*

CUSTOMER	# OF CARS	DESTINATION	USE
Dakota Gas	87	Beulah, ND	Industrial Boiler
Texpar	3	Milwaukee, WI	Small Boilers
3 M Company	14	Hutchinson, MN	Industrial Boiler
Kiesel	2	St. Louis, MO	Blend W/ #6 Oil
US Steel	2	Chicago, IL	Steel Mill Blast Furnace
Michigan Marine	18	Detroit, MI	Blend W/ #6 Oil
M&S Petroleum	40	Lake Charles, LA	Fuel Oil Blend
Baka Energy INC.	6	Houston, TX	Fuel Oil Blend

Table 3. Summary Of CDL™ Tank Car Shipments *(Through 11/15/96)*

CHALLENGES

A detailed review of equipment and plant modifications through July 1995 has been presented[1,3,5]. Table 4 summarizes the major challenges that have been overcome and the solutions implemented.

AREA OF PLANT	DEFINITION OF PROBLEM	SOLUTION
Electrostatic Precipitators	Insulator Failures	Modified Insulators, Improved Temperature Control
Material Handling	Plugging and Spillage	Modified S-belts & Chutes
PDF™ Quenching and Steam Condenser	Oil and Coal Dust, Too Small	Added Scrubber, Added 2 Larger Exchangers
Dryer and Pyrolyzer	Sand Seal Failures	Replaced With Water Seals
Combustors	Unstable Operation	Revised Control System
Pumps and Blowers	Sizing Problems, Mostly Too Small	Replaced With Larger Equipment
Changing Process Variables	Initial Plant Design Parameters Were Off	Adjusted Operating Set Points
PDF™ Dust Collection	Dusty Conditions On Product Side of Plant - No Scrubbers	Added Two Wet Scrubbers
PDF™ Deactivation	Could Not Produce Stable PDF™ In Original Equipment	Added VFB Deactivation Loop Equipment
Process Water System	Accumulation Of Oily Fines In Process Equipment	Installed Clarifier, Floc & Vacuum Filter
Cyclone Fines Handling	Loss Of Excessive Amounts Of PDF™ In Cyclone Fines, Labor Intensive Clean-up	Recovered VFB Deactivation Fines Into PDF™ Product, Reduced Handling System
VFB Drag Conveyors	Excessive Wear and Maintenance Intensive	Redesigned High Wear Points, Modified Discharges To Reduce Plugging
Plant Operability And Maintenance	Difficult Access, Labor Intensive Clean-up, Inflexible To Operate	Piping Revisions, Access Platforms And Doors, Relocate Valves

Table 4. Summary Of Plant Modifications

Still to be solved are several challenges involving plant capacity, PDF™ deactivation, and removal of coal fines from the CDL™. In addition, CDL™ upgrading even on the small scale of the ENCOAL® plant, appears to be economically attractive as well as something that needs to be tested before application in a large commercial plant. Data collection and designs are complete for the plant capacity improvements and PDF™ finishing projects, and work on the other projects scheduled for next year is in progress.

PDF™ Deactivation

Total product deactivation remains a key challenge. At the present time, the PDF™ is not completely stabilized in the plant but has to be "finished" by a short exposure to atmospheric conditions external to the plant. ENCOAL® has recently completed pilot-scale equipment tests that successfully performed this finishing step using process equipment. The design uses commercially available equipment to be installed just downstream of the rotary cooler, and will effectively stabilize PDF™ on a continuous basis. Installation of this equipment is currently scheduled in 1997.

Plant Capacity

One known bottleneck remains that prevents attainment of full design capacity of 1,000 TPD. The VFB loop is the limiting factor, since it was designed for 50% of plant capacity. A second unit was planned once the effectiveness of the PDF™ deactivation process was demonstrated. After the PDF™ finishing equipment mentioned above is installed, the addition of the second VFB may be required to reach full plant capacity.

CDL™ Upgrading

The ENCOAL® plant was intentionally designed to capture a single, wide-boiling-range liquid product, CDL™ , as opposed to making multiple liquid fractions. This was done to simplify the operation, lower the capital cost and reduce the risk associated with the added complication of liquid separations. It was determined that this would be evaluated after the basic LFC™ Technology had been demonstrated. Attention has now been turned to CDL™ upgrading since the plant has moved into a production mode.

Some preliminary feasibility and design work has indicated that upgrading of the CDL™ both in the ENCOAL® plant and on a commercial scale makes economic sense; indeed it may be required to produce products that can be sold in quantity in existing markets. The M. W. Kellogg Company developed a design and cost estimate for modifying the existing plant for upgrading CDL™ in 1995. The design used information from laboratory studies and a complete CDL™ chemical characterization to develop the a workable process.

The basic concept is to produce three commercially viable streams; (1) a transportation grade fuel feedstock that would include most of the aliphatic compounds present in CDL™, (2) a tar acid fraction that would include the cresylic acids, phenols and light aromatics and (3) a heavy residual bottom that would be suitable as anode binder pitch. This concept is currently being considered for implementation in the ENCOAL® plant to demonstrate its potential for commercial- sized LFC™ plants as well as to enhance the economics of continued operation of the existing plant.

CDL™ Solids Removal

The pyrolyzer loop cyclone was specifically designed to remove the coal fines from the gas stream prior to recovery of the CDL™ in the quench tower and ESP's. However, the cyclone does not effectively remove all of the fines, and the CDL™ consequently has 2 to 4% entrained solids. All CDL™ upgrading schemes identified to date have indicated that the fines in the CDL™ are undesirable. The fines must therefore be removed or reduced in quantity in order to meet customer requirements for any sale other than fuel oil. Testing of various methods of solid/liquid separation techniques is ongoing, and installation of a system at the ENCOAL® plant is scheduled in 1997.

PDF™ Properties

After 4½ years of operation and production of 97,900 tons of PDF™, the properties of PDF™ that can be produced in the plant are fairly well defined. The variables that are controllable to some extent in the process are the heat content, volatiles, and moisture. The components dictated by the composition of the feed coal are ash, sulfur, size consist, and hardness. The LFC™ process has little impact on the ash composition or ash fusion temperature. Test data have been presented in previous reports[3] that show the variability of the PDF™ with process conditions. Table 5 represents the averages of the PDF™ that are currently being made at the ENCOAL® plant.

PROXIMATE ANALYSIS	PLANT RUN	LAYDOWN BLEND	TARGET
Heat Content (Btu/lb)	11,112	10,682	11,400 - 11,600
Moisture (%)	9.81	10.1	8 - 9
Ash (%)	7.56	7.9	6 - 9
Volatile Matter	25.93	26.7	21 - 24
Fixed Carbon (%)	56.70	54.8	57 - 60
Sulfur (%)	0.41	0.52	0.51 Maximum
OTHER			
Hardgrove Grindability	47	43	45 - 50
#Sulfur/MMBtu	0.37	0.40	0.45 Maximum
#SO_2/MMBtu	0.74	0.81	0.90 Maximum
Ash Mineral Analysis	Same as coal	Same as coal	Same as coal
Ash Fusion Temperature	2220°F	2220°F	2220°F

Table 5. Average Representative Properties of PDF™

CDL™ Properties

Like PDF™, the properties of CDL™ are influenced by the pyrolyzer operation. However, the properties of CDL™ are also influenced by operation of equipment in the pyrolysis gas loop, including the pyrolyzer cyclone, the quench tower and the electrostatic precipitators. These directly affect the amount of water and sediment in the CDL™. Again, a significant amount of data has been presented in previous reports[3], so only the following summary table is presented here. A significant amount of work has been done on the detailed chemical characterization of CDL™ for the upgrading project discussed above. This work is ongoing and will be the subject of future reports.

	CDL™	Low Sulfur Fuel Oil
API Gravity (°)	1.3 - 3.2	5
Sulfur (%)	0.3 - 0.5	0.8
Nitrogen (%)	0.6	0.3
Oxygen (%)	6.2	0.6
Viscosity @ 122°F (cs)	280	420
Pour Point (°F)	66 - 90	50
Flash Point (°F)	165	150
MBtu/gal	140	150
Water (wt %)	0.5	<1
Solids (wt %)	2 - 4	<1
Ash (wt %)	0.2 - 0.4	<1

Table 6. Average CDL™ Quality

COMMERCIALIZATION

ENCOAL® Corporation has a sublicense for the LFC™ Technology from the TEK-KOL Partnership. The Partnership, owned by SGI International and a subsidiary of Zeigler Coal Holding Company, is responsible for the commercialization and licensing of the LFC™ Technology and thus is carrying out ENCOAL's obligation under the Cooperative Agreement. Under the TEK-KOL Partnership Agreement, SGI International is designated as the Licensing Contractor responsible for licensing and promoting the LFC™ Technology. Zeigler is the administrative partner responsible for preparation of lease agreements and contracts.

Commercialization of the LFC™ Technology consists of marketing the products, PDF™ and CDL™, to interested consumers at prices that will support the construction of commercial plants. Concurrently, the LFC™ Technology must be licensed to the prospective plant owners. These may or may not be the same as the consumers of the products. The technology and product marketing activities are closely interwoven and are carried out by both TEK-KOL partners. For the most part, ENCOAL® carries out allZeigler partnership activities.

In order to determine the viability of potential LFC™ plants, TEK-KOL has already completed several detailed commercial plant feasibility studies (called Phase II studies as described previously [3]). These studies include plant design, layout, capital estimates, market assessment for co-products, operating cost assessments, and overall financial evaluation. Operation of the

ENCOAL® plant provided the basis for estimating operating cost and commencing product market development, and unlike most upgrading projects, full-scale shipment and test burns made possible by the near-commercial size of the ENCOAL® plant has provided actual market information for the basis of these studies. Operating experience of the ENCOAL® facility was also used for the design basis and capital estimates. In February 1996, TEK-KOL and Mitsubishi Heavy Industries (MHI) signed an agreement to jointly produce Design and Engineering Cost Estimates for commercial LFC™ plants. This arrangement combines the scientific, engineering, and operating experience of the TEK-KOL staff with the engineering and design experience of MHI to produce a comprehensive study. To date, three detailed LFC™ Phase II studies have been completed by the TEK-KOL/MHI team. These studies are discussed below.

Domestic Markets

The most promising markets for the application of the LFC™ Technology in the U.S. are the subituminous coal deposits in the Powder River Basin. Close behind are the subituminous reserves in Alaska's Beluga field, lignites in North Dakota, followed by Texas lignites near San Antonio. Testing on all of these coals has been conducted in the TEK-KOL Development Center (Center) Sample Production Unit (SPU) with favorable results.

Application of the LFC™ Technology to swelling or agglomerating coals is not feasible at this time, so most of the central and eastern U.S. coals are not candidates. Removal of sulfur by the LFC™ process has proven to be significant, especially when the sulfur form is highly organic, but these bituminous coals would still be too high in sulfur after processing to meet the amended clean air act requirements. Central and eastern U.S. coals are also more costly to mine than western subituminous coal, leaving less margin for upgrading. For these reasons, central and eastern U.S. coals do not appear to be promising candidates for LFC™ processing.

Powder River Basin. A large portion of the extensive U.S. coal reserves lie in the Powder River Basin in Montana and Wyoming. Subituminous and low in sulfur, this coal is ideal for processing via the LFC™ Technology. That is a major reason the ENCOAL® plant was located near Gillette. The southern end of the PRB in Wyoming is of special interest because the sulfur and ash are especially low. Here the PDF™ product may have an increased value for metallurgical applications or as a super compliance blending material.

Overall, the PRB has the lowest mining costs in the U.S. and, being a long distance from the major utility markets, has the highest transportation costs. This combination yields a large differential value between the raw material cost and the delivered cost. The high incremental value, a well developed transportation infrastructure, qualified, available labor force and a large number of operating mines mean that the opportunities for installation of commercial LFC™ plants are very good for the PRB.

A Phase II technical and economic feasibility study was completed on one potential PRB site in 1996. This study was for a commercial-size LFC™ plant to be located at Triton Coal Company's North Rochelle Mine site. The site includes three 5,500 ton feed coal/day LFC™ modules, a 240

MW cogeneration plant, and CDL™ upgrading facilities integrated with the mine-site infrastructure. Results of the study indicated that the project has a financible rate of return *(>15%)* without any government subsidies, price supports, or tax credits. In other words, the LFC™ products compete in current markets at current prices. However, the aid of government tax incentives would help off-set the financial risk associated with a project of this magnitude. This study was recently refined in order to confirm the project economics, and to assemble design information for submittal of permit applications required by the State of Wyoming to allow construction to begin. An air permit application was submitted in November 1996 followed by Land Quality and Industrial Siting Permits around the end of the year.

Alaska. There are two promising areas in Alaska for the installation of commercial LFC™ plants, namely the Beluga fields and the Healy deposits. Both areas have extensive reserves, are largely subituminous in nature and have low ash and sulfur. The Beluga coal is very near the Cook Inlet with the possibility of a deep water port for exports. However there is essentially no infrastructure to produce these reserves and this would be a costly venture. Current owners of the three main lease areas have not been able to attract buyers of the coal in the current market. Mine development would have to be included in any LFC™ plant venture.

At Healy, there is an existing producing mine and coal is shipped by rail to the coast for export. The Healy coal has been tested at the Center with good results. However the cost of mining is fairly high, transportation costs are high and there is no local market. The PDF™ and CDL™ from a project in this area may have difficulty competing with other locations.

North Dakota Lignite. Significant reserves of lignites are present in the Williston Basin of North Dakota and tests on some of them indicate good potential for LFC™ processing. Lab tests have indicated that good quality PDF™ and acceptable yields of CDL™ are produced using LFC™ Technology. Most recently, these coals have been further tested at the Center for mechanical strength during processing, also with positive results.

Overall, the economics of commercial LFC™ plants for the North Dakota lignites appear attractive. The coal seams are relatively thick and the sulfur and ash content are low, although not as low as the PRB. However, North Dakota is closer to some important markets. This coal is being considered for an alternate coal test in the ENCOAL® plant.

Texas Lignite. Numerous tests on Texas lignites have been conducted at the Center. With some lignites, the PDF™ quality and CDL™ recoveries have proven to be acceptable. However, other Texas lignites, although extensively available, are not considered to be viable candidates because of poor coal quality. Coal quality combined with proximity of the existing lignite mines near power plants designed to burn ROM material, makes the application of an LFC™ plant unlikely in the near future. Interest in exporting upgraded Texas lignites into other markets, or applying an LFC™ facility to replace an existing coal drying process would be two most likely scenarios for a Texas based facility.

International Markets

TEK-KOL is also actively pursuing international opportunities for applying the LFC™ Technology. Primary areas of immediate interest are in China, Indonesia, and Russia. These areas have been identified by TEK-KOL as the most likely to develop in the near future, and accomplishments in these areas are discussed in more detail below. Other potential international applications for the LFC™ Technology *(such as the Pacific Rim, Southeast Asia, India and Pakistan, Eastern Europe, and Australia)* that have previously been discussed[5], have been identified by TEK-KOL as longer range development projects. For this reason, progress in these areas is not discussed in this paper.

China. China is the largest producer as well as the largest consumer of coal in the world. Over a third of the coal production occurs in the three northern provinces of Shanxi, Shaanxi and Inner Mongolia. However, due to significant transportation infrastructure problems, it is not always possible to move the coal within China to meet local needs. As a result of the extremely high economic growth in the southern and eastern coastal regions of China accompanied by a parallel demand for new electrical power, there are predictions that China may require imports of coal in the range of 10-50 million tons per year by 2010. Furthermore, the predictable result of burning such prodigious quantities of coal, much of it high in sulfur, is an environmental problem of such magnitude that it is a major concern not only of the Chinese government but also for the governments of neighboring countries and, indeed, the world.

For these reasons, China is viewed as one of the prime candidates for application of the LFC™ Technology. The LFC™ Technology offers China the opportunity:

- to more efficiently and effectively employ its vast resources of coal
- to conserve scarce and valuable railroad assets as a result of the moisture reduction aspect of the LFC™ Technology
- to vastly expand its exports into the world steam coal and metalurgical markets and, thereby, generate much needed foreign revenue
- to augment valuable and increasingly scarce petroleum assets through the production of CDL™
- to reduce the extremely severe pollution problems associated with burning high sulfur coal

The LFC™ Technology has been actively promoted in China for several years with the Ministry of Coal Industry (MOCI) and officials of regional coal mine administrations by explaining the value of employing the LFC™ Technology and developing potential commercial plant projects. Although China has huge quantities of bituminous and anthracite coal, it also has great reserves of subituminous and lignite coals that are ideal candidates for upgrading using the LFC™ Technology. MOCI expressed keen interest in the advantage to China offered by the LFC™ Technology and representatives of SGI International have visited various mining areas in China that could be potential sites for LFC™ projects.

Indonesia. Approximately 93% of Indonesia's reported 36+ billion metric tons of reserves are in the form of subituminous and lignite coal. Significantly, though, this accounts for over 97% of the identified recoverable reserves in all of the Asian countries. These reserves are split approximately 70% on the island of Sumatra and 30% on the island of Kalimantan. In fact, the Indonesian reserves have not been definitively studied yet and there exists some question as to the full extent of the identified and hypothetical reserves. On a positive note, the vast majority of the mines are open-cut operations enjoying thick seams and are mostly located near the coast or close to a navigable river, facilitating ready access to international as well as domestic markets.

Indonesia's rapid economic growth during the past decade has fueled an increase in the demand for electrical power that has grown at 11-15% per year. Furthermore, although Indonesia has been a major exporter of oil, as a result of the surging domestic growth and the limited oil reserves, it is predicted to become a net importer of petroleum by the year 2000. While a significant portion of the coal production will be destined to feed the growing domestic electrical power and industrial needs, Indonesia also requires the foreign exchange credits which will result from increasing the export market. Consequently, it is under strong pressure to better exploit its vast reserves ofsubituminous and lignite coal.

Toward this end, work has been ongoing in Indonesia for over five years to promote the advantages of the LFC™ Process in answering many of Indonesia's needs. The coal industry is dominated by P.T. Tambang Batubara Bukit Asam (PTBA), the state coal mining corporation which operates under the Ministry of Mines and Energy. The structure of the industry includes the state-owned mines operated by PTBA, national companies contracted by PTBA under coal concession contract agreements, private domestic companies operating under mining concessions issued by PTBA and a few local area coal cooperatives.

Employment of the LFC™ process to upgrade low-rank coal would permit Indonesia, which is closer to Japan, South Korea, Taiwan and Hong Kong, to become very competitive in the steam coal markets. A Phase I study on some thirteen different samples indicated that several of the coals of the Tanjung Enim region of South Sumatra were good-to-excellent candidates for upgrading using the LFC™ process. Indonesia, which is short on invesment capital, submitted a request to the U.S. Trade and Development Agency (TDA) for a grant for a Phase II study. This grant was approved by the TDA, and a Phase II study was completed in September 1996. This project included one to three LFC™ modules with a range of 40 to 100 MW of cogeneration, along with CDL™ upgrading facilities, transportation infrastructure, and living quarters. The study did not include the development and operation of the adjacent mine. Economics of the PTBA study were encouraging, and efforts to sign a contract with PTBA to conduct a more detailed investigation are underway.

Additionally, one Phase II study on a site adjacent to a P.T. Berau Lati Mine in East Kalimantan was completed. The study included a single LFC™ module, 40MW cogeneration plant, and a CDL™ upgrading facility that was located adjacent to the existing mine river shipping station. This one module LFC™ plant case resulted in moderate economics due to its limited throughput and relatively high operating cost. The Lati Mine coal was determined to be exceptional candidate for upgrading using the LFC™ Technology. However, local infrastructure issues, including the price of feed coal, must be resolved before the situation becomes favorable for a profitable development of a commercial LFC™ project.

Opportunities continue to be pursued in Indonesia from Aceh at the northern tip of Sumatra to lignite mines in Sulawesi. The value of the LFC™ Technology to Indonesia parallels very closely the advantages mentioned for China. Where China enjoys huge production capabilities in all forms of coal, it is especially important to Indonesia to upgrade the vast reserves of subituminous and lignite coals in order to participate effectively in the world steam coal market. Much of Indonesian coal is already naturally low in sulfur, so the resulting PDF™ is particularly attractive to markets in Japan. Work is continuing with MHI and other Japanese firms interested in cooperating in the development of projects in Indonesia and the rest of Asia.

Russia. Russia accounts for about 60% of the coal production of the former Soviet Union with almost all the rest coming from Ukraine and Kazakhstan. The increasing importance of coal to the fuel and energy balance of Russia must be viewed with the understanding of the major drop in crude oil production and decreased growth rate of gas production. Representatives of the Russian coal group ROSUGOL and the Kemerovo Coal Certification Center in south central Siberia have been evaluating a project using the LFC™ Technology in the Kemerovo region. Following a visit to SGI's offices in La Jolla, California and the ENCOAL® Plant in Gillette, Wyoming, Russian representatives signed a letter of intent to proceed with Phase I and Phase II studies for an LFC™ project. The Russian delegation was particularly excited about the value added by the production of CDL™ which is so important in view of reduced oil production. The Phase I study was completed in late 1995, and indicated that the coals tested were suitable for LFC™ upgrading. Work on a Phase II study is expected to begin in 1997 pending Russian agreement to proceed. If successful, this Russian endeavor could be the first of many projects in this country with huge potential reserves.

Long Term Impact Of LFC™ Commercialization

The LFC™ Technology is uniquely positioned in the world coal conversion and upgrading market to impact two widely used fossil energy forms, namely solids and liquids. Many technologies have successfully demonstrated the conversion of coal to synthetic gases which are in turn used as a clean energy source. Others have demonstrated the manufacture of hydrocarbon liquids from these synthetic gases to serve as chemical or transportation fuel feedstocks. Still other technologies have demonstrated the technical feasibility of direct conversion of coal to hydrocarbon liquids. Although not truly coal conversion, coal upgrading by removal of undesirable constituents like water, sulfur and ash has also been extensively demonstrated on a commercial scale by numerous technologies. The LFC™ Technology alone produces both an upgraded solid product and hydrocarbon liquids.

Economic conditions for typical commercial coal conversion and upgrading projects are generally absent without some form of political intervention, such as price supports, grants, subsidies or artificial market constraints. While tax credits would be helpful on the first LFC™ plant to offset risks, commercial LFC™ plants can compete in today's markets at today's prices with attractive rates of return. Therefore, countries with significant indigenous coal reserves (like the U.S.) or countries with significant investment or material supply interests (like Japan), should be able to use the LFC™ Technology to further economic growth.

Of course there are practical limits to the application of the LFC™ Technology. Some of the criteria for successful commercial projects can be generally stated as:

- Significant coal reserves - greater than 150 million ton block for a 3 module LFC™ plant
- Non caking, non agglomerating coal - like most low rank coals
- Low mining costs
- Low ash and inorganic sulfur content
- Located near navigable water or other reasonably priced accessible form of transportation
- Favorable political climate
- Markets for products for products at acceptable prices

There are many coal deposits in the world today which meet all of these criteria.

Consumers of solid and liquid energy products, which more and more is a world-wide market, should see significant advantages in the products from commercial LFC™ plants. The benefits for the consumer can be summarized as:

- Reduced dependance on petroleum based liquid products and the widely variable prices in that market
- Reduced environmental impact from the burning of PDF™ and CDL™ in the form of lower SO_x and NO_x as demonstrated by test burns. LFC™ plants are also very environmentally benign
- Lower fuel costs for power plants and industrial boilers on a fully utilized basis
- Long term, stable fuel supply
- Unique characteristics for metallurgical and ferroally markets
- For consumers with coal reserves, incresed use of domestic resources

Given the widespread availability of qualified candidate coals and the numerous benefits that accrue to consumers of the LFC™ products, commercialization of the LFC™ Technology should be able to make a major long term positive impact on the world energy picture. TEK-KOL and the commercial LFC™ plant development team are actively pursuing these opportunities.

FUTURE WORK

The next step in the Project is to continue to deliver high quality, pure PDF™ to utility customers and potential steel industry and ferroally users for test burns. These deliveries will aid in the development of future PDF™ markets and help secure product contracts for commercial LFC™ plants. Work on installing PDF™ finishing equipment, plant capacity upgrades, and CDL™ solids removal systems are expected in 1997. Installation and operation of these systems will provide the operation data and experience important for the final design and construction of a commercial

LFC™ facility.

The goal is to maintain better than 90% availability on the plant this year and complete any remaining major plant modifications by the end of 1997. Efforts to commercialize the LFC™ Technology will continue both at home and abroad. The evaluation of CDL™ upgrading will also continue and a decision made about proceeding with an ENCOAL® plant modification.

CONCLUSIONS

The ENCOAL® Project has completed most of its goals. Essentially all the major Cooperative Agreement Milestones have been met, and final reporting requirements will be completed in early 1997. The debugging phase is complete and steady state operation has been achieved. The LFC™ Technology is essentially demonstrated and marketable PDF™ and CDL™ are being produced.

Significant quantities of both products have been shipped and successfully used by customers, thus proving them to be acceptable fuel sources in today's markets. Efforts to commercialize the LFC™ Technology, both domestically and internationally, are in progress.

REFERENCES

1. J.P. Frederick, "Design, Construction And Start-Up Of The ENCOAL® Mild Coal Gasification Project", First Annual Clean Coal Technology Conference, U.S. Department Of Energy, Cleveland, OH, September, 1992

2. T.G. McCord, "The ENCOAL® Project: Initial Commercial Shipment And Utilization Of Both Solid And Liquid Products", U.S. Department Of Energy Topical Report, August 1995

3. J.P. Frederick, R.E. Nickell, "Continuous Operation And Commercialization Of The ENCOAL® Mild Coal Gasification Project", Third Annual Clean Coal Technology Conference, U.S. Department of Energy, Chicago, IL, September, 1994.

4. J.P. Frederick, "Design and Construction Of The ENCOAL® Mild Coal Gasification Project", U.S. Department Of Energy Topical Report, August 1995

5. J.P. Frederick, S.A. van Hoften, "Commercialization of the Liquids From Coal Process", Fourth Annual Clean coal Technology Conference, U.S. Department of Energy, Denver, CO, July 1995.

6. S.A. Johnson, B.A. Knottnerus, "Results of the PDF™ Test Burn at Clifty Creek Station", U.S. Department of Energy Topical Report, October 1996.

GLOSSARY

AEP	American Electric Power
AS	American Society of Testing Methods
°API	American Petroleum Institute measure of oil density
BACT	Best Available Control Technology
Btu	British Thermal Unit
Center	TEK-KOL Development Center in Perrysburg, Ohio
CDL™	Coal Derived Liquid
CO	Carbon Monoxide
CH_4	Methane
DOE	U. S. Department of Energy
ENCOAL®	ENCOAL® Corporation, a wholly owned subsidiary of Bluegrass Coal Development Co., which is a wholly owned subsidiary of Zeigler Coal Holding Co.
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic Precipitators
IKEC	Indiana-Kentucky Electric Cooperative
lb.	Pound
LFC™	Liquid From Coal
MHI	Mitsubishi Heavy Industries, Hiroshima, Japan
MMBtu	Million British Thermal Units
MOCI	Ministry of Coal Industry
MT	Metric Tonnes
N/A	Not Available
NO_x	Nitrogen Oxides
OPPD	Omaha Public Power District, Omaha, Nebraska
OSHA	Occupational Safety & Health Administration
PDF™	Process Derived Fuel
PRB	Powder River Basin
ROM	Run-of-mine
S-Belt	Vertical conveyor with flexible sidewalls and rubber buckets
SGI	SGI International, LaJolla, CA
SMC	SMC Mining Company, Evansville, IN *(name changed to Bluegrass Coal Development Co.)*
SO_2	Sulfur Dioxide
SPU	Sample Production Unit, TEK-KOL Development Center
Std. Dev.	Standard Deviation
TEK-KOL	A general partnership between SGI International and a subsidiary of Zeigler Coal Holding Company
TGA	Thermogravimetric analysis, procedure for analyzing coal and PDF™
TPD	Tons Per Day
vs.	Versus
WP&L	Wisconsin Power and Light
wt.	Weight
#	Pound

The Changing Face of International Power Generation

Ian Lindsay
Secretary General
World Energy Council

Fifth Annual Clean Coal Technology Conference
"Powering the next Millennium"
January 7-10, 1997
Tampa, Florida

Ladies and Gentlemen,

I think it was Churchill in his great Iron Curtain speech at Fulton, Missouri, at the end of the last war, who referred to the American and the British as "Two great peoples divided by a common language" - I sincerely hope his remark will prove invalid today. At least during lunch, we will not have to resort to instantaneous translation as I did a few months ago in Moscow, when I was giving another short talk. Towards the end I noticed that terrible glazed look on the faces of the audience, which betrayed the fact that I had said something - through the interpreter - which was obviously totally incomprehensible. In fact I had used the expression "Out of sight, out of mind," but it was not until afterwards that I discovered it had been translated as "Invisible Idiot." Let that be a lesson against using the vernacular.

Before starting, just a few words about the World Energy Council. It was started in 1923, and with over a hundred member countries, is today the world's prime energy strategy and analysis organisation. Our study projects carry input from the industrialised world, the developing world, and of course the economies in transition in E. Europe and the Former Soviet Union. Almost more important, by working "bottom up" from the grass roots of local energy sectors we both collect input from the operatives - the very people, like yourselves, who manage energy - and we cross-fertilise data, information, and the results of our study work worldwide. We are increasingly acting as "facilitators" to "get things done." An example was holding the first ever African Energy Ministers Conference, which concentrated on power pooling arrangements and the first attempts at coordinated regional energy development. Before the conference such interconnections really only existed in the seven Southern African countries. Today, 1½ years later, interconnections are already being started in the six East African countries, the Arab Grid is being extended in the Maghreb (North Africa), and a central plan has recently been approved for power pooling in the French-speaking countries of Central and West Africa.

Although we are non-commercial and non-governmental, we work closely with governments the world over, as well as with over 40 of the leading institutions in the energy and energy-related sectors

- the World Bank, the principal regional financing agencies, the single energy associations - The World Petroleum Congresses, International Gas Union, UNIPEDE the European electricity institution, the World Trade Organisation, International Chamber of Commerce, the UN in all its guises, etc.

You may well not have heard of us if you are not intimately concerned with the international energy scene. Alternatively, you may have heard or seen references too much of the longer term work we do, but in either case I would suggest you are going soon to hear a lot more about us. The WEC US Member Committee is based in Washington and called the US Energy Association. Every three years we hold a major international Congress, always in a different country, and the next, the 17th WEC Congress, is being organised by the USEA in Houston in September 1998. Barry Worthington, its Executive Director, is with us today, and if you want to know more about its menu and attractions, please ask him.

"The Changing Face of International Power Generation" is a subject which could occupy several hours, but don't let me give you indigestion too early on. I will limit my remarks not to changing technologies and improved performance, not to changing fuel mixes, not to the incessant - but so far unproven CO_2 problems, not to SO_x's and NO_x's, of which you will have had your fill during this Conference, **BUT** to the international generator's marketplace, and even here I will devote little of what I have to say to the OECD countries but much to the developing world.   I shall speak to future global electricity demand, generating capacity build, its financing issues, and to the commercial generating opportunities which now abound outside the States.

Such a rich diet may go some way to proving Voltaire's maxim that "Thinking depends on the stomach."   So, while I remain hungry, you can chew over what I have said, because I get the very pronounced feeling in the current turbulence caused by the upheavals in your own domestic power sector, that US utilities are missing out on commercial opportunities in many overseas markets which, with prudence, could eventually offer attractive returns.

First of all, the general context. Energy demand perspectives including our own, those of the IEA, the World Bank and others, all point to a virtual doubling of global primary energy demand over the next 25 years. Let me interpret what that means. By 2020 more than 90m b/d of oil are likely to be consumed annually - an increase over today of 27m b/d, or the whole of OPEC's current crude oil production. Annual coal output will double to about 7 billion tonnes - almost double the entire known reserves in Canada or the UK. Annual gas demand will more than double to approximately 4 trillion cubic meters - almost equal to the entire current US gas reserves. In all this, fossil fuels will continue to dominate the global energy sector for decades to come, albeit with some ultimate growth of both nuclear and hydro. We see new renewables (solar, wind, etc.) remaining at or close to their 2% - 3% share of today's global demand, unless massive government or other funds are allocated to support their growth. Energy lead times are long and it is unlikely over the next 25 years that new renewables will either make in-roads into existing systems or play much of a part in the incremental growth during this time, unless the potential CO_2 problem becomes a scientific reality.

So much for the contextual perceived wisdom. It is not until these global demand figures are analysed, however, that the picture becomes clearer as to where or why the main demand will occur.

Up to 2020 it is likely that some 90% of this natural energy growth will occur in the developing countries - mainly in Asia and Latin America. North America, by contrast, will probably experience only a 12% - 13% growth up to 2020, while the 60% of global demand consumed by the OECD will drop to under 50% for the first time. By contrast, the developing countries demand will increase from 28% today to about 40% of the total by 2020. The East European and CIS demand is likely to remain constant at about 13%. But in this alarmingly short space of only 25 years, let us go further into the analysis. 90% of incremental energy demand growth will occur in developing countries, because of rapid population growth and economic development and the fact that growth in many cases will start from a low base. Over half of this incremental growth is likely to take place in just six areas: China, India, Indonesia, Brazil, Pakistan and the Malaysia/Thailand peninsula.

What of electricity generating capacity in all this? Well, we in the WEC, like many others, are predicting that more generating capacity will be built in the next 25 years than was built in the last one hundred. Much of this will result from the rapid urbanisation of developing countries, and much from the march of technology in transmitting power efficiently over much greater distances. In 1960 only 28 countries had greater urban than rural populations By 2020, 88 countries are expected to have 50% or more of their populations living in cities. Cities like Delhi, São Paulo, Manila, Bombay, Beijing, Jakarta and Teheran are all recording annual population growth rates of +3% or more - and do not forget that an annual growth rate of 3% means a doubling of population in 23 years. Do not also forget the result of a recent IEA study which showed that per capita consumption of energy in urban and peri-urban areas is usually between 2.5 and 3.0 times that experienced in rural communities. As an example of the long haul grid transmission, the huge 40 Gigawatt Inga hydro scheme on the Zaire River as the future supplier to markets as far afield as Egypt and Southern Africa, separated by 8,000 miles, is probably only some 20 years off. The feasibility study is already nearing completion and the political and economic in-fighting has already begun, not only for the project itself, but also for grid wayleaves, etc.

In 1920 Lenin defined communism as “Soviet power plus the electrification of the whole country.” He meant by this the projection, in one leap, of the whole of a backward country into the forefront of industrialisation. He might have been proved right had it not been for the might of your own economy together with those of others and backed by our political wills to overcome. However, let us concentrate today not on the flagging energy sectors of Eastern Europe and the CIS - where, to give you some idea of current economic regression, the Russian Federation consumed 20% less oil in 1994 than it did in 1993 - not on the slow growth of the OECD generating sectors - but on the developing countries and their rapidly expanding electricity demand.

Here we should differentiate between what I call “old assets” (existing power systems) and “new assets,” involved in the massive incremental growth of the power generating sector. The growth of these “new assets” is not only a phenomenon in its own right, it is turning out to be a considerable stimulus for global capitalism. Let us not forget that the global power sector at nearly 40% is by far the world’s greatest absorber of infrastructure capital. Electricity development consumes more finance than communications, highways, or water. It also carries huge political clout. A developing country politician can win more votes faster - if he or she operates within a voting system - by bringing in electrification to a village. Go to a country like Uganda and you will see this. Rural power development there has not followed any logical pattern - it has largely followed the whims of individual ministers. Utilities in many such countries have until now been government owned and run, financed starved and the primary cause of lack of industrial productivity due to black and brown outs and general inefficiency. Often their revenues did not even cover their fixed costs because to a greater or lesser degree governments supported subsidies to consumers, who in many cases were unable economically to pay tariffs which covered costs.

Approximately 60% of all energy supplied globally to consumers today is subsidised by governments in one form or another - and a large part of this 60% inevitably occurs in the developing world. Consumer tariffs are therefore often low and many do not allow of a decent return on capital invested. So, with regard to such "new assets" the message must be to investigate and take action with great prudence and almost inevitably in conjunction with a local partner which knows the local scene.

But all this is changing. Governments faced with huge and increasing demand for electrification and new assets, are realising that they cannot cope with the pressures for finance, control and the day-to-day management and maintenance essential for all this new capacity. This has resulted in a number of different national reactions. On the one hand markets are being liberalised - although by different methods and at different rates, and this may offer commercial opportunities for the astute external investor: But, on the other hand, developing country governments often maintain their ingrained belief that energy must belong to the national patrimony, and some are correspondingly reluctant to adequately loosen controls. This causes a range of problems.

"Old electricity assets," the existing power systems, are in many cases also being liberalised. Let me give you some examples. Brazil is about halfway through its privatisation programme. Chile has fully privatised with adequate commensurate changes to government regulation to ensure overall economic and social success. Argentina is in the process of privatising by individual sector, generating, transmission and marketing. The Venezuelan electricity sector now has local private investors as well as foreign owned assets. In Africa, Egypt has privatised its generating sector. Kenya Light and Power, previously 100% government owned, now has only a minority government shareholding. In Zimbabwe ZESA, the national generator, with some 2,000Mw now has Malaysian minority shareholders, who will become majority shareholders when capacity is increased by 50% over the next 4 years. Of almost more importance, industrial consumer prices in Zimbabwe have been increased by some 250% and the "new asset" investment in generating capacity has a planned 20% real rate of return. In Zambia, the Copperbelt Power Company is to be sold; in Botswana a privatisation plan is to be announced shortly; and in Namibia local private sector shareholders now own all the principal generating and transmission assets. Further south, South Africa is in the throes of liberalising its power sector which generates 67% of all the power in the Continent of Africa.

In Asia, China and India, with some 10% of total current global electricity demand, are planning to build new capacity up to 2020 which, by that year, could equate to 25% of global generation. This could mean the construction of a medium sized power station every week up to 2020. In Malaysia and Indonesia, power demand is growing faster than the already rapidly expanding economies.

But there are caveats; relate all this growth to population predictions and you will find that by 2020 China, for example, will still only have a per head generating capacity equal to 30% that of the US today. Such rapid growth in the developing world coming on top of a lack of finance, often poor technical management, and equally poor financial control, is now faced with a fourth quandary - that of increasing local pressure to apply very much more stringent environmental protection controls first in a local sense, and probably thereafter in a global sense.

We in the WEC have done some work with the World Bank, which shows that international financing (from both agency and private sector sources) will probably cover only between 30% - 40% of the huge future requirements of the electricity sector. In my view, the outstanding questions in this entire growth scenario are "Where will the other 60%-70% come from?", and "Will the potential lack of financing become a real constraint to growth?" Can, or will, many developing countries not only liberalise their power sectors but render then sufficiently attractive to investors to mobilise local capital? And at the same time will they set up the necessary institutions to attract the often high local savings rates? To know more about all this we now await the outcomes of two current WEC study projects, due to be completed shortly: the first on "Liberalisation of the Global Energy Sector," and the second on "Future Energy Financing." The results will make fascinating reading.

The scale of such private power development of itself probably presents the greatest problem of all. As an example, private sector power development may, in India, be regarded as the solution to one of the country's major development problems, but internal bureaucracy, the rivalry between government departments, and the way legal process work have all combined to slow down the whole process of private investment. Foreign investment rates, having soared during the last three years in Malaysia, Indonesia, Argentina and Chile, have also now begun to slow down. And over this whole scene is cast the shadow of the debt crisis of the 1980s. About 30% of the money then lent to Third World governments was to have been invested in power projects. Today's scene is different, but nonetheless tense. Today's investors are considerably more prudent than yesterday's, and the loans do not necessarily go to governments but it is still necessary for such agencies as the World Bank to provide some political protection by themselves taking small stakes in satisfactory projects. Risks however remain, not least depreciating exchange rates and the inability of governments to change regulations and tariffs at the same rate as they encourage private sector investments.

This, then, is the heart of the changing face of international power generation as seen by the WEC. Let me encourage you to come and hear much more about it, by participating in the WEC's 17th Congress to be held in Houston from 13th - 18th September 1998. We are expecting between 6,000 and 7,000 delegates to the event, one of a series which over the years have established themselves as the prime global events of the international energy scene.

If I have given you indigestion, this can only have resulted from one of two causes - boredom, in which case you have my apologies; or from a surfeit of information, in which case you have my commiseration. But above all, let us not forget that to operate in the developing world we all have to deal primarily with local politics and local politicians, and in this context you may care to remember the little aphorism of one of our British maverick socialist politicians, Lord Charlfont, who maintained that "you can always rely on politicians to produce wise, intelligent and statesmanlike decisions .... having first exhausted all other options!"

THE CLEAN COAL TECHNOLOGY PROGRAM
10 MWe DEMONSTRATION OF GAS SUSPENSION ABSORPTION FOR FLUE GAS DESULFURIZATION

Frank E. Hsu
Jorgen G. Hedenhag
AirPol Inc.
32 Henry Street
Teterboro, New Jersey

Sharon K. Marchant
George W. Pukanic, Ph.D.
Pittsburgh Energy Technology Center
United States Department of Energy
Pittsburgh, Pennsylvania

Verrill M. Norwood, Ph.D.
Thomas A. Burnett
Technology Advancements
Tennessee Valley Authority
Chattanooga, Tennessee

U.S. DEPARTMENT OF ENERGY
FIFTH ANNUAL
CLEAN COAL TECHNOLOGY CONFERENCE
January 7-10, 1997
Tampa, Florida

ABSTRACT

AirPol Inc., with the cooperation of the Tennessee Valley Authority (TVA) under a Cooperative Agreement with the United States Department of Energy, installed and tested a 10 MWe Gas Suspension Absorption (GSA) Demonstration system at TVA's Shawnee Fossil Plant near Paducah, Kentucky. This low-cost retrofit project demonstrated that the GSA system can remove more than 90% of the sulfur dioxide from high-sulfur coal-fired flue gas, while achieving a relatively high utilization of reagent lime.

This paper presents a detailed technical description of the Clean Coal Technology demonstration project. Test results and data analysis from the preliminary testing, factorial tests, air toxics tests, 28-day continuous demonstration run of GSA/electrostatic precipitator (ESP), and 14-day continuous demonstration run of GSA/pulse jet baghouse (PJBH) are also discussed within this paper.

I. INTRODUCTION

AirPol, with the assistance of the Tennessee Valley Authority (TVA), demonstrated the Gas Suspension Absorption (GSA) technology in the Clean Coal Technology project entitled "10 MW Demonstration of Gas Suspension Absorption." AirPol performed this demonstration under a Cooperative Agreement awarded by the United States (U.S.) Department of Energy (DOE) in October 1990. This project was selected in Round III of the Clean Coal Technology Program.

This project was the first North American demonstration of the GSA system for flue gas desulfurization (FGD) for a coal-fired utility boiler. This low-cost retrofit project achieved the expected target, which was to remove more than 90% of the sulfur dioxide (SO_2) from the flue gas while achieving a high utilization of reagent lime. TVA furnished its Center for Emissions Research (CER) as the host site and provided operation, maintenance, and technical support during the project. The CER is located at the TVA's Shawnee Fossil Plant near Paducah, Kentucky.

The experience gained by AirPol in designing, fabricating, and constructing the GSA equipment through the execution of this project will be used for future commercialization of the GSA technology. The results of the operation and testing phase will be used to further improve the GSA system design and operation.

The specific technical objectives of the GSA demonstration project were the following:

- Demonstrate SO_2 removal in excess of 90% using high-sulfur U.S. coal.
- Optimize design and operating parameters to maximize the SO_2 removal efficiency and lime utilization.
- Compare the SO_2 removal efficiency of the GSA technology with existing spray dryer/electrostatic precipitator (SD/ESP) technology.

DOE issued an amendment to the Cooperative Agreement to include the additional scope of work for air toxics testing and also the operation and testing of a 1 MWe fabric filter pilot plant in cooperation with TVA and the Electric Power Research Institute (EPRI). The two-fold purpose of this additional work was the following:

- Determine the air toxics removal performance of the GSA technology.
- Compare the SO_2, particulate, and air toxics removal performance between GSA/ESP and GSA/fabric filter systems.

The fabric filter used in this project is a pulse-jet baghouse (PJBH) which can treat flue gas removed either upstream or downstream of the ESP. The testing of the PJBH was conducted for both configurations.

The total budget for the project with the added scope of work was $7,720,000; however, the project cost was under the budget. The favorable variance resulted mainly from actual material and construction costs being much lower than the original estimate. The performance period of the project, including the air toxics measurements, PJBH testing, and report preparation was from November 1990 to June 1995.

AirPol began the design work on this project in November 1990, shortly after award of the Cooperative Agreement by DOE in October 1990. At the outset of the project, access to the site at the CER was delayed for one year by TVA to allow the completion of another project. That caused a one-year delay in this Clean Coal Technology project. The design phase of the GSA project was completed in December 1991. The fabrication and construction of the GSA unit was completed ahead of schedule in early September 1992. The planned operation and testing of the demonstration unit were conducted from late October 1992 to the end of February 1994.

II. HISTORY OF THE GSA TECHNOLOGY

The GSA process is a novel concept for FGD that was developed by AirPol's parent company, F.L. Smidth miljo a/s in Copenhagen, Denmark. The process was initially developed as a cyclone preheater system for cement kiln raw meal (limestone and clay). This innovative system provided both capital and energy savings by reducing the required length of the rotary kiln and lowering fuel consumption. The GSA system also showed superior heat and mass transfer characteristics and was subsequently used for the calcination of limestone, alumina, and dolomite. The GSA system for FGD applications was developed later by injecting lime slurry and the recycled solids into the bottom of the reactor to function as an acid gas absorber.

In 1985, a GSA pilot plant was built in Denmark to establish design parameters for SO_2 and hydrogen chloride (HCl) absorption for waste incineration applications. The first commercial GSA unit was installed at the KARA Waste-to-Energy Plant at Roskilde, Denmark, in 1988. Currently, there are seventeen GSA installations in Europe; 15 are municipal solid waste incinerator applications, and two are industrial applications (cement and iron ore reduction).

With the increased emphasis on SO_2 emissions reduction by electric utility and industrial plants as required by the Clean Air Act Amendments of 1990, there is a need for a simple and economic FGD process, such as GSA, by the small to mid-size plants where a wet FGD system may not be feasible. The GSA FGD process, with commercial and technical advantages confirmed in this demonstration project, will be a viable alternative to meet the needs of utility and industrial boilers in the U.S.

III. GSA FGD PROCESS DESCRIPTION

The GSA FGD system, as shown in the Figure 1 Process Flow Diagram, includes:

- A circulating fluidized bed reactor.
- A separating cyclone incorporating a system for recycling the separated material to the reactor.
- A lime slurry preparation system which proportions the slurry to the reactor via a dual-fluid nozzle.
- A dust collector which removes fly ash and reaction products from the flue gas stream.

The flue gas from the boiler air preheater is fed into the bottom of the circulating fluidized bed reactor, where it is mixed with the suspended solids that have been wetted by the fresh lime slurry. The suspended solids consist of reaction products, residual lime, and fly ash. During the drying process in the reactor, the moisture in the fresh lime slurry, which coats the outer surface of the

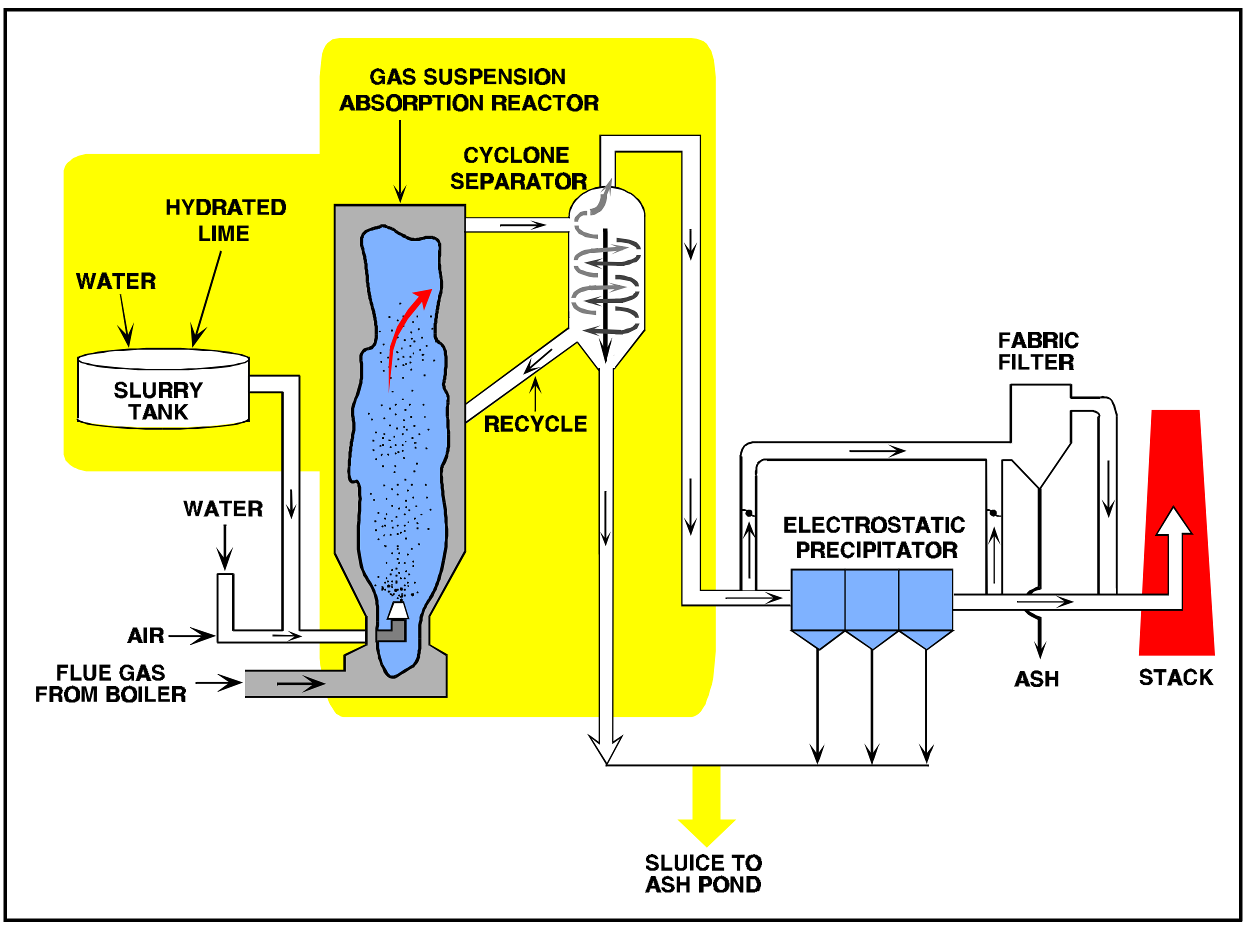


Figure 1. Gas Suspension Absorption Process Flow Diagram

suspended solids, evaporates. Simultaneously, the lime particles in the slurry undergo a chemical reaction with the acid components of the flue gas, SO_2 and HCl, capturing and neutralizing them.

The partially cleaned flue gas flows from the top of the reactor to the separating cyclone and then to an ESP (or a fabric filter), which removes the dust and ash particles. The flue gas, which has now been cleaned, is released into the atmosphere through the stack.

The cyclone separates most of the solids from the flue gas stream. Approximately 95% to 99% of these collected solids are fed back to the reactor via a screw conveyor, while the remaining solids leave the system as a byproduct material. Some of these solids recirculated to the reactor are still reactive. This means that the recirculated lime is still available to react and neutralize the acid components in the flue gas.

The pebble lime is slaked in a conventional, off-the-shelf system. The resulting fresh slaked lime slurry is pumped to an interim storage tank and then to the dual-fluid nozzle. The slurry is diluted with trim water prior to being injected into the reactor.

Automatic Process Adjustment

An effective monitoring and control system automatically ensures that the required level of SO_2 removal is attained while keeping lime consumption to a minimum. This GSA control system, which is shown in Figure 2, incorporates three separate control loops:

1. Based on the flue gas flow rate entering the GSA system, the first loop continuously controls the flow rate of the recycled solids back to the reactor. The large surface area for reaction provided by these fluidized solids and the even distribution of the lime slurry in the reactor, provide for the efficient mixing of the lime with the flue gas. At the same time, the large volume of dry material prevents the slurry from adhering to the sides of the reactor.

2. The second control loop ensures that the flue gas is sufficiently cooled to optimize the absorption and reaction of the acid gases. This control of flue gas temperature is achieved by the injection of additional water along with the lime slurry. The amount of water added into the system is governed by the temperature of the flue gas exiting the reactor. This temperature is normally set a few degrees above flue gas saturation temperature to insure that the reactor solids will be dry so as to reduce any risk of acid condensation.

3. The third control loop determines the lime slurry addition rate. This is accomplished by continuously monitoring the SO_2 content in the outlet flue gas and comparing it with the required emission level. This control loop enables direct proportioning of lime slurry feed according to the monitored results and maintains a low level of lime consumption.

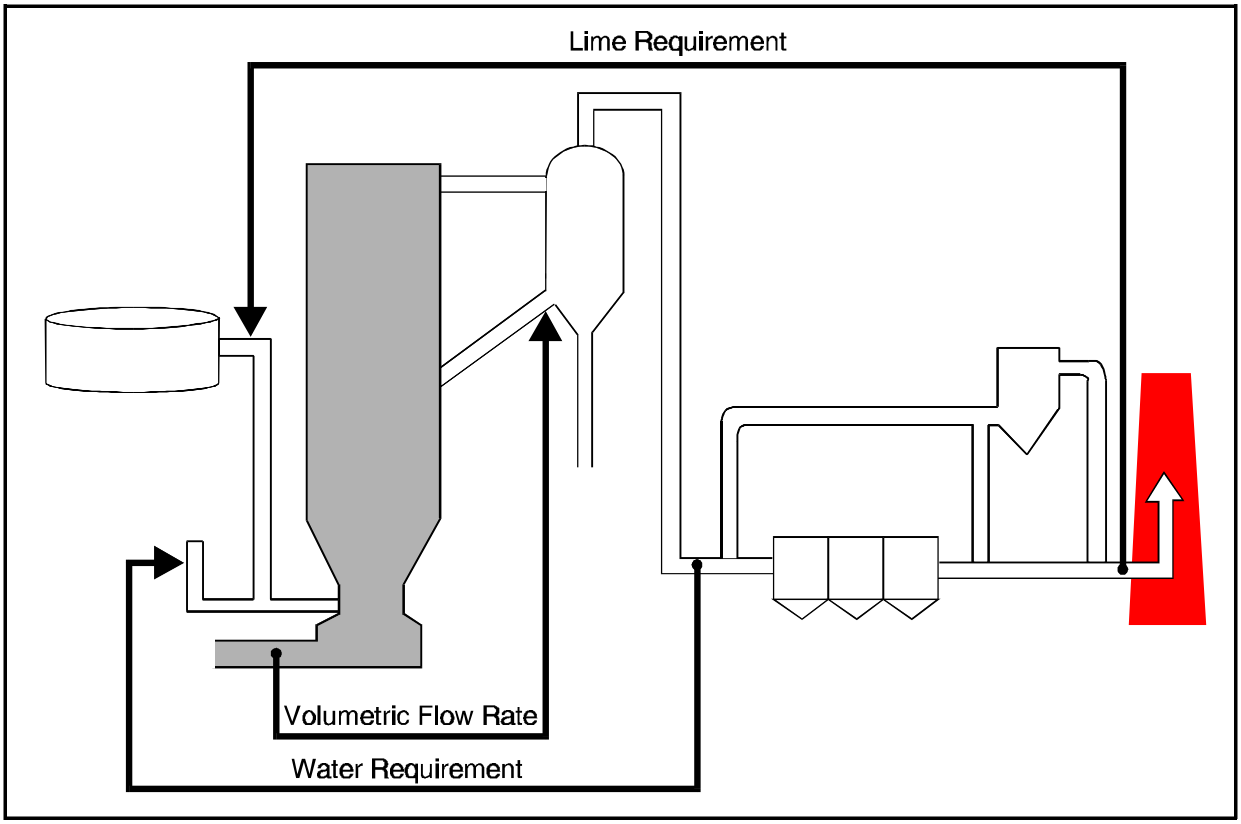


Figure 2. Gas Suspension Absorption Control System

IV. COMPARISON OF GSA PROCESS WITH COMPETING TECHNOLOGY

Simplicity is the key feature of the GSA system. The advantages of the GSA system over competing technologies are summarized as follows:

<u>Slurry Atomization</u>

The major difference between GSA and competing technologies lies in the way the reagent is introduced and used for SO_2 absorption. A conventional semi-dry scrubber:

- Requires a costly and sensitive high-speed rotary atomizer or a high-pressure atomizing nozzle for fine atomization,

- Absorbs SO_2 in an "umbrella" of finely atomized slurry with a droplet size of about 50 microns,

- May require multiple nozzle heads or rotary atomizers to ensure fine atomization and full coverage of the reactor cross section, and

- Uses recycle material in the feed slurry necessitating expensive abrasion-resistant materials in the atomizer(s).

The GSA process, on the other hand,

- Uses a low-pressure, dual-fluid nozzle,

- Absorbs SO_2 on the wetted surface of suspended solids with superior mass and heat transfer characteristics,

- Uses only one spray nozzle for the purpose of introducing slurry and water to the reactor, and

- Uses dry injection of recycle material directly into the reactor, thereby avoiding erosion problems in the nozzle or technical limitations on the amount of solids that can be recycled.

Simple and Direct Method of Lime/Solid Recirculation

The recirculation of used lime is the trend for semi-dry scrubbing systems. The recirculation of solids in the GSA system is accomplished using a feeder box under the cyclone, which introduces the material directly into the reactor. The recirculation feature commonly used in most other semi-dry processes has an elaborate ash handling system to convey and store the ash. The method of introducing the recirculated material is usually by mixing it with the fresh lime slurry. The presence of ash in the lime slurry may cause sediment problems in the slurry lines and excessive nozzle wear.

High Acid Gas Absorption

The GSA reactor is capable of supporting an extremely high concentration of solids (recirculated material) inside the reactor, which acts like a fluidized bed. This concentration will normally be as high as 200-800 grains/scf. These suspended solids provide a large surface area for contact between the lime slurry (on the surface of the solids) and the acidic components in the flue gas. This high contact area allows the GSA process to achieve levels of performance that are closer to those of a wet scrubber, rather than a dry scrubber. Since drying of the solids is also greatly enhanced by the characteristic large surface area of the fluidized bed, the temperature inside the reactor can be reduced below that of the typical semi-dry scrubber. This lower operating temperature facilitates acid gas removal in the GSA system.

Low Lime Consumption / Minimum Waste Byproduct Residue

The design of the GSA reactor allows for more efficient utilization of the lime slurry because of the high internal recirculation rate and precise process control. The higher lime utilization (up to 80%) lowers the lime consumption, thereby minimizing one of the major operating costs. In addition, the lower lime consumption reduces the amount of byproduct generated by the system.

Low Maintenance Operation

Unlike typical semi-dry scrubbers, the GSA system has no moving parts inside the reactor, thus ensuring relatively continuous, maintenance-free operation. The orifice diameter of the GSA injection nozzle is much larger than that used in a conventional semi-dry process, and there is little chance for it to plug. Nozzle wear is also minimized. Should the need for replacing the nozzle arise, it can be replaced in a few minutes. The cyclone also has no moving parts. Both the reactor and the cyclone are fabricated from unlined carbon steel.

The GSA process also has few pieces of equipment. Most of the equipment is in the lime slurry preparation area, which typically is an off-the-shelf item, and the technology is well known.

No Internal Buildup

By virtue of the fluidized bed inside the reactor, the inside surface of the reactor is continuously "brushed" by the suspended solids and is kept free of any buildup. Internal wall buildup can be a problem with the conventional semi-dry scrubber. There is also no wet/dry interface on any part of the equipment and this avoids any serious corrosion problem.

Modest Space Requirements

Due to the high concentration of suspended solids in the reactor, the reaction occurs in a relatively short period of time. A high flue gas velocity of 20 to 22 feet per second as compared to 4 to 6 feet per second for a semi-dry scrubber, as well as the shorter residence time of 2.5 seconds as compared to 10 to 12 seconds for a semi-dry scrubber, allow for a smaller diameter reactor which leads to a considerable reduction in space requirements.

Short Construction Period

The compact design of the GSA unit requires less manpower and time to be erected as compared to the typical semi-dry scrubbers. Despite the relatively complicated tie-ins and extremely constrained work space, the retrofit GSA demonstration unit at the TVA's CER was erected in three and a half months.

Heavy Metals Removal

Recent test results from waste incineration plants in Denmark indicate that the GSA process is not only effective in removing acidic components from the flue gas but is also capable of removing heavy metals, such as mercury, cadmium, and lead. This heavy metal removal capability of the GSA process at the CER was confirmed by the air toxics tests.

V. PROJECT STATUS AND KEY MILESTONES

The project schedule and tasks involved in the design, construction, and operation and testing phases are as follows:

		Start - End
Phase I - Engineering and Design		
1.1	Project and Contract Management	11/01/90-12/31/91
1.2	Process Design	11/01/90-12/31/91
1.3	Environmental Analysis	11/01/90-12/31/91
1.4	Engineering Design	11/01/90-12/31/91
Phase II - Procurement and Construction		
2.1	Project and Contract Management	01/01/92-09/30/92
2.2	Procurement and Furnish Material	01/01/92-04/30/92
2.3	Construction and Commissioning	05/01/92-09/30/92
Phase III - Operating and Testing		
3.1	Project Management	10/01/92-12/31/94
3.2	Start-up and Training	10/01/92-10/14/92
3.3	Testing and Reporting	10/15/92-06/30/95

The parametric optimization tests were completed on schedule in August 1993. Following the air toxics testing, which was finished in October 1993, there was a 28 day, around-the-clock demonstration run from the later October to late November 1993 and a 14-day, around-the-clock PJBH demonstration run from late February to mid-March 1994. All testing has been completed and the project reports have been prepared.

VI. TEST PLAN

A test plan was prepared to depict in detail the procedures, locations, and analytical methods to be used in the tests. All of the following objectives were achieved by testing the GSA system:

- Optimization of the operating variables.
- Determination of stoichiometric ratios for various SO_2 removal efficiencies.
- Evaluation of erosion and corrosion at various locations in the system.
- Demonstration of 90% or greater SO_2 removal efficiency when the boiler is fired with high-sulfur coal.
- Determination of the air toxics removal performance.
- Evaluation of the PJBH performance in conjunction with the GSA process.

Optimization Tests

The optimization of the SO_2 removal efficiency in the GSA system was accomplished through the completion of a statistically-designed factorial test plan. For each test series, the GSA system was set to operate at a certain combination of operating parameters. The results of these test series were analyzed statistically to determine the impact of the parameters, thus arriving at the optimum operating point for the GSA process at the various operating conditions expected in future applications. Operating parameters studied in this phase of the project were the following:

- Inlet flue gas flow rate
- Inlet flue gas temperature
- Inlet dust loading
- Solids recirculation rate
- Stoichiometric ratio
- Approach-to-saturation temperature
- Coal chloride level

Data Collection

The following data were sampled and recorded during the tests by either the computerized data sampling and recording system (via field mounted instruments) or by manual field determinations:

- Inlet flue gas flow into the system
- SO_2 loading at the system inlet, SO_2 loading at the ESP inlet and outlet
- Flue gas temperature at the system inlet, the reactor outlet, and the ESP outlet
- Particulate loading at the ESP inlet and outlet
- Fresh lime slurry flow rate and composition (for lime stoichiometry calculation)
- Water flow rate
- Wet-bulb temperature at the reactor inlet (for approach-to-saturation temperature calculation)
- Coal analysis (proximate and ultimate)
- Lime analysis
- Byproduct rate and composition
- Water analysis
- Power consumption

VII. PRELIMINARY TESTING

Immediately after the dedication of the AirPol GSA demonstration plant in late October 1992, a series of preliminary tests was begun. The purpose of these tests was to investigate the operating limits of the GSA system as installed at the CER. The results from several of the preliminary tests completed at the CER in November and December were very interesting, and these results were used as the basis for the design of the factorial test program. During one of the preliminary tests, the approach-to-saturation temperature in the reactor was gradually decreased and the overall system (reactor/cyclone and ESP) SO_2 removal efficiency was monitored over this four-day test. The overall system SO_2 removal efficiency increased from about 65% to more than 99% at the closest approach-to-saturation temperature (5°F). The other conditions, which remained constant, were 320°F inlet flue gas temperature, 1.40 moles $Ca(OH)_2$/mole inlet SO_2 for the lime stoichiometry, and essentially no chloride in the system. The SO_2 removal results from this test are shown in Figure 3.

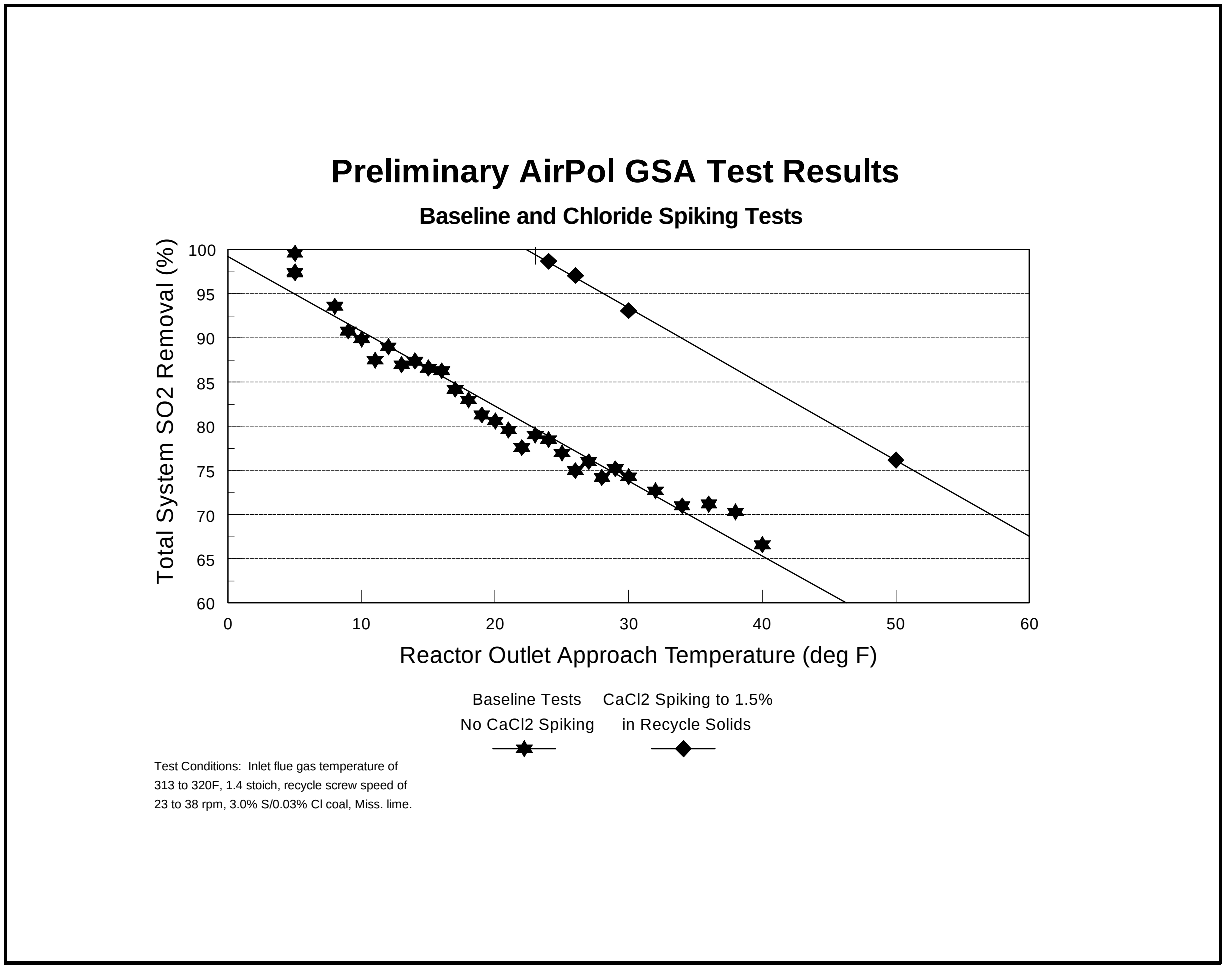


Figure 3. Preliminary AirPol GSA Test Results

The data from this test show that the SO_2 removal efficiency increased dramatically as the flue gas temperature in the reactor more closely approached the saturation temperature of the flue gas, with the incremental increases in SO_2 removal becoming more and more significant as the approach-to-saturation temperature declined. The ability of the GSA system to operate at this close approach-to-saturation temperature without any indication of plugging problems was surprising. Later analysis showed that the moisture level in the solids remained below 1%.

A second extended test was run during December 1992. This test was run at the same conditions as the previous test, except that in this test, calcium chloride was added to the system to simulate the combustion of a high-chloride (about 0.3%) coal. Previous work by TVA at the CER had demonstrated that spiking these semi-dry, lime-based FGD processes with a calcium chloride solution adequately simulated a high chloride coal application. Again, the approach-to-saturation temperature was gradually decreased over a four-day period with all other conditions held constant and the overall system SO_2 removal efficiency was monitored. The results from this second test, which are included in Figure 3 above, show that the presence of chlorides enhances SO_2 removal.

The overall system SO_2 removal efficiency for the chloride-spiked tests increased from about 70% at the high approach-to-saturation condition to essentially 100% at the closer approach-to-saturation temperature (23ºF). No attempt was made to operate the system at the close approach-to-saturation temperatures used in the first test because the SO_2 removal efficiency was approaching 100%. In addition, there were initially some concerns about the secondary effect of calcium chloride addition. Calcium chloride is an ionic salt that tends to depress the vapor pressure of water in the system and thus, slows the evaporation of water from the slurry. Calcium chloride is also a hygroscopic material, which means it has the ability to absorb moisture from the humid flue gas. The increased moisture in the "dry" solids allows more reaction with SO_2, but also increases the potential for plugging in the system. The easiest method for mitigating this potential for plugging is to increase the approach-to-saturation temperature in the reactor. However, the moisture levels in the solids during this test remained below 1%, even at the closest approach-to-saturation temperature.

Another interesting finding from the preliminary testing is that the GSA process is capable of supporting a very high level of recirculation material in the reactor. This high solid concentration inside the reactor is the reason for the superior drying characteristics of the GSA system. Based on the results from these initial tests, the recycle rate back to the reactor was doubled prior to starting the factorial testing.

VIII. FACTORIAL TESTING

The purpose of the statistically-designed factorial test program was to determine the effect of process variables on the SO_2 removal efficiency in the reactor/cyclone and the ESP.

Based on the successful preliminary testing, the major process design variables were determined, levels for each of these variables were defined, and an overall test plan was prepared. The major variables were approach-to-saturation temperature, lime stoichiometry, fly ash loading, coal chloride level, flue gas flow rate, and recycle screw speed. Two levels were determined for nearly all of the variables, as shown in Table 1 below. The one exception was the approach-to-saturation temperature where three levels were defined, but the third level was run only for those tests at the lower coal chloride level.

Major Variables and Levels for Factorial Testing Table		
Variable		Level
Approach-to-saturation temperature	^oF	8[a], 18, and 28
Ca/S	moles $Ca(OH)_2$/mole inlet SO_2	1.00 and 1.30
Fly ash loading	gr/acf	0.5 and 2.0
Coal chloride level	%	0.02 and 0.12
Flue gas flow rate	kscfm	14 and 20
Recycle screw speed	rpm	30 and 45
[a] 8^oF level run only at the low-chloride level		

Table 1. Major Variables and Levels for Factorial Testing

Although the preliminary chloride spiking tests had not been run at an approach-to-saturation temperature below 23^oF, the decision was made to complete these chloride-spiking factorial tests at an 18^oF approach-to-saturation temperature. There was some risk in this decision because the water evaporation rate decreases at the higher chloride levels. However, based on previous test work at the CER, the expectation was that at the lower chloride levels in this test plan, equivalent to a coal chloride level at 0.12%, the GSA system could operate at the 18^oF approach-to-saturation temperature condition.

IX. RESULTS OF FACTORIAL TESTING

<u>SO_2 Removal Efficiency</u>

The overall system SO_2 removal efficiency results from these factorial tests have been analyzed, and several general relationships have become apparent. First, as was expected based on previous testing at the CER, significant positive effects on the SO_2 removal efficiency in the system came from increasing the lime stoichiometry and other factors such as increasing the coal chloride level or decreasing the approach-to-saturation temperature. Increasing the recycle rate resulted in higher SO_2 removal, but the benefit appeared to reach an optimum level, above which further increases in the recycle rate did not seem to have a significant effect on SO_2 removal. Increasing the flue gas flow rate had a negative effect on the SO_2 removal in the system.

The overall system SO_2 removal efficiency during these tests ranged from slightly more than 60% to nearly 95%, depending on the specific test conditions. The higher SO_2 removal efficiency levels were achieved at the closer approach-to-saturation temperatures (8 and 18°F), the higher lime stoichiometry level (1.30 moles $Ca(OH)_2$/mole inlet SO_2), and the higher coal chloride level (0.12%). The lower SO_2 removal efficiency levels were achieved at the higher approach-to-saturation temperature (28°F), the lower lime stoichiometry level (1.00 mole $Ca(OH_2$/mole inlet SO_2), and the lower coal chloride level (0.02-0.04%). The data from these factorial tests completed at these conditions are shown in Figure 4. The slight scatter in the data in this figure is due to the variations

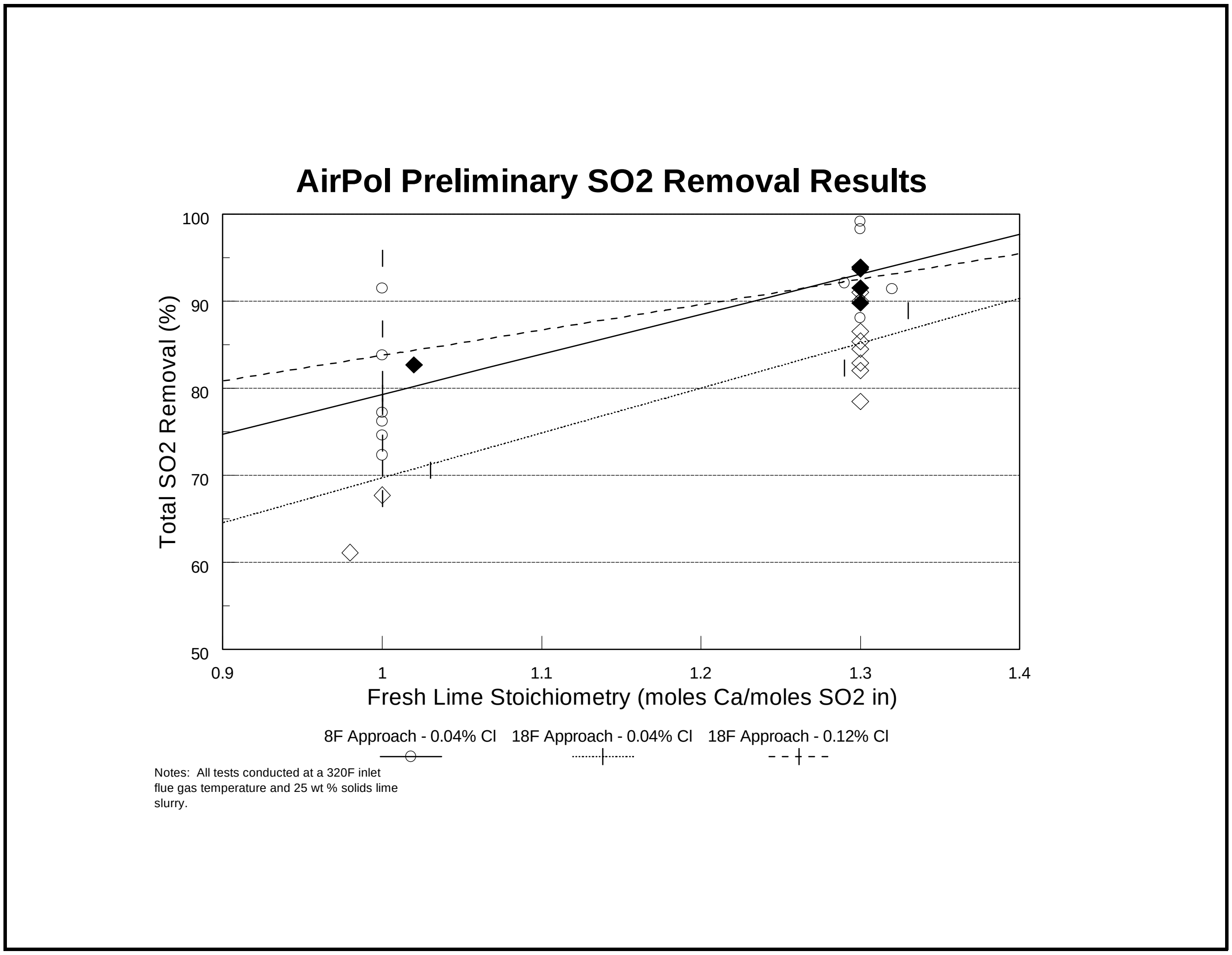


Figure 4. Overall System SO_2 Removal Results from the GSA Factorial Testing

in the other major process variables in these tests (i.e. flue gas flow rate, recycle screw speed, etc.). Most of the SO_2 removal in the GSA system occurs in the reactor/cyclone, with only about 2 to 5 percentage points of the overall system removal occurring in the ESP. There was substantially less SO_2 removal in the ESP than in previous testing at the CER, but the overall system SO_2 removal efficiencies appear to be comparable with the GSA process for most test conditions.

As one would expect, the lime stoichiometry level, which was tested at 1.00 and 1.30 moles $Ca(OH)_2$/mole inlet SO_2, seems to have the most significant effect on the SO_2 removal efficiency in the GSA system.

The approach-to-saturation temperature, which was evaluated at three levels of 8, 18, and 28°F for the low coal chloride conditions and the two levels of 18 and 28°F for the higher coal chloride condition, appears to be the second most important variable in the GSA system in terms of the overall system SO_2 removal efficiency.

The third most important variable seems to be the chloride level in the system. Two coal chloride levels were tested, the baseline coal chloride level of 0.02 to 0.04% and the equivalent of a 0.12% coal chloride level. The higher chloride level was achieved by spiking the feed slurry with a calcium chloride solution.

One of the most surprising results of this factorial testing was the ability of the GSA system to operate at an 8°F approach-to saturation temperature at the low-chloride condition without any indication of plugging. This is even more impressive given the very low flue gas residence time in the reactor/cyclone. The second interesting result of this testing was the ability of the GSA system to operate at the 18°F approach-to-saturation temperature at the higher chloride level. In the preliminary testing at a much higher coal chloride level (0.3%), the lowest approach-to-saturation temperature tested was 23°F. No operating problems were encountered in the tests completed at the 0.12% coal chloride level and 18°F approach-to-saturation temperature conditions. In fact, the average moisture level in the solids remained below 1.0% in all of these factorial tests, even at the higher coal chloride level.

ESP Performance

The ESP installed at the CER is a relatively modern, 4-field unit with 10-inch plate spacing, similar in design to several full-scale ESPs installed on the TVA Power System. This unit has 23-feet-high plates with 8 parallel gas passages. The specific collection area (SCA) of the unit is about 440 ft^2/kacfm under the cooled, humidified flue gas conditions downstream of the reactor/cyclone. (For the untreated flue gas at 300°F, i.e., in a fly-ash-only application, the SCA of this ESP is about 360 ft^2/kacfm.)

The particulate removal performance of this ESP was determined for each of the factorial tests, even though this was not the primary focus of the testing. The most important result of this particulate testing was that the emission rate from the ESP was substantially below the New Source Performance Standards (NSPS) for particulates (0.03 lb/MBtu) at all of the test conditions evaluated as shown in Figure 5. The typical emission rate was 0.010 lb/MBtu. The particulate removal efficiency in the ESP for nearly all of the tests was above 99.9% and the outlet grain loadings were below 0.005 gr/acf.

However, during the testing there were disturbing indications of low power levels in the first field of the ESP, particularly in those tests involving chloride spiking. In some of these chloride-spiking tests completed at the high flue gas flow rate (20,000 scfm), the power level in the first field was only about 5% of the normal level, effectively meaning that the first field had "collapsed." Even with these low power levels in the first field of the ESP, the particulate removal efficiencies were still 99.9+ percent and the emission rate was in the range of 0.010 lb/MBtu. The cause of these low power levels in the first field of the ESP is being investigated. These low power levels could be the result of a number of factors, including plate-wire alignment problems as observed in a recent internal inspection.

One surprising result of this ESP testing was that there was no significant improvement in the ESP performance with increasing SCA. For some of these tests, the SCA in the ESP approached 800 ft^2/kacfm and the flue gas velocity in the ESP dropped below 2.0 ft/sec and yet the emission rate remained in the same range as in the other tests, i.e., 0.010 lb/MBtu.

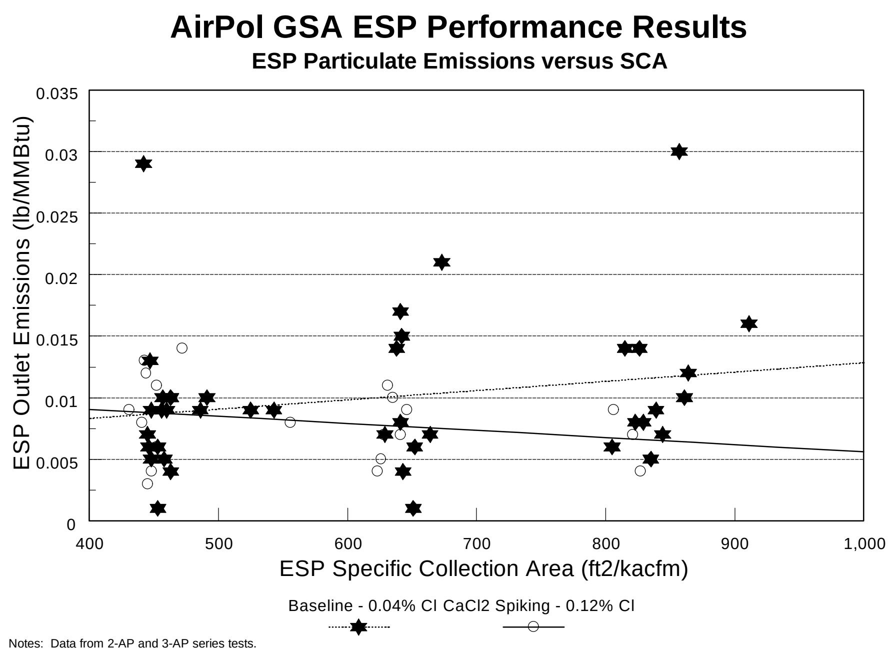


Figure 5. ESP Performance Results from the GSA Factorial Testing

Pulse Jet Baghouse Performance

Although not part of the original GSA project, TVA and EPRI had co-funded the installation of a 1-MWe PJBH pilot plant at the CER to be operated in conjunction with the existing GSA demonstration. Later, AirPol and DOE joined in the operation and testing of this PJBH pilot plant program. The PJBH pilot plant, which was started up in late January, can pull a slipstream of flue gas from either the ESP inlet or outlet, as shown in Figure 1. In the first series of factorial tests, the PJBH pilot plant pulled flue gas from the ESP inlet and, thus, treated flue gas with the full particulate loading (3 to 5 gr/acf) from the GSA reactor/cyclone. The inlet flue gas flow rate was about 5,000 acfm, which corresponds to an air-to-cloth ratio (A/C) of 4.0 acfm/ft^2 in the PJBH. During the second series of factorial tests, the PJBH pilot plant pulled flue gas from the ESP outlet. The same inlet flue gas flow rate was treated (5,000 acfm), but two-thirds of the bags were removed prior to this testing and thus, the A/C for these tests was 12 acfm/ft^2.

The cleaning of the bags in the PJBH was pressure-drop-initiated during this testing with the cleaning cycle beginning whenever the tubesheet pressure drop reached 6 inches of water. The cleaning continued until the tubesheet pressure drop had declined to about 4-1/2 inches of water. The bags were cleaned by a low-pressure, high-volume, ambient air stream delivered by a rotating manifold.

SO_2 Removal Efficiency for Reactor/Cyclone/PJBH System

The SO_2 removal efficiency in the reactor/cyclone/PJBH system was typically about 3-5 percentage points higher than that achieved in the reactor/cyclone/ESP system at the same test conditions. This higher SO_2 removal efficiency in the PJBH system was not unexpected given the intimate contact between the SO_2-laden flue gas and the solids collected on the outside of the bags as the flue gas passed through the filter cake and the bags before being discharged to the stack. However, it should be noted that most of the SO_2 removal occurred in the reactor/cyclone; the PJBH SO_2 removal efficiency, based on the inlet SO_2 to the reactor, contributed less than 8 percentage points to the overall system SO_2 removal efficiency during this testing.

Particulate Removal

The particulate removal efficiency in the PJBH was 99.9+ percent for all of the tests completed with the full dust loading from the GSA reactor/cyclone. The emission rate for all of these tests was well below the New Source Performance Standards for particulates and was typically in the range of 0.010 lb/MBtu.

X. AIR TOXICS TESTING

The air toxics tests, which followed the factorial tests, were conducted during September and October, 1993. The objectives of these tests were to:

- Determine emissions and net removal efficiency of hydrogen chloride (HCl), hydrogen fluoride (HF), total particulate matter and trace metals. The trace metals included antimony (Sb), arsenic (As), barium (Ba), beryllium (Be), cadmium (Cd), chromium (Cr), cobalt (Co), lead (Pb), manganese (Mn), mercury (Hg), nickel (Ni), selenium (Se) and vanadium (V).

- Evaluate the impact of the particulate control device configuration (ESP alone, PJBH alone, or ESP plus PJBH in series) on final emissions of hazardous air pollutants.

- Compare the emissions of HCl, HF and trace metals with and without the injection of lime slurry.

The tests were conducted in two configurations, i.e. with the PJBH in series and parallel with the ESP. Two test conditions were evaluated for each configuration: baseline, with no lime introduction into the system; and demonstration, with lime slurry injection. Three simultaneous sampling runs were performed at each of the four permutations. The streams sampled are shown in Table 2.

Type of Sample	Location
Gaseous	GSA inlet, ESP inlet, ESP outlet, PJBH inlet and PJBH outlet
Aqueous	Lime slurry and trim water
Solid	Coal, GSA cyclone, ESP field 1, ESP field 2,3,4, PJBH hopper and re-injected fly-ash

Table 2. Sampling Locations For The Air Toxics Tests.

All of these tests were completed while the boiler was burning the high-sulfur (2.7%), low-chloride Andalex coal and were run at the high flue gas flow rate (20,000 scfm) and the high fly ash loading (2.0 gr/acf) test conditions. The baseline tests were performed at 270°F GSA reactor inlet temperature to protect the acrylic bags in the PJBH. The demonstration tests operated at 320°F GSA reactor inlet temperature, with a 12°F approach to saturation temperature at the GSA outlet.

XI. RESULTS OF AIR TOXICS TESTING

Tables 3 and 4 present the removal efficiencies and uncertainties of the baseline and demonstration case with varying ESP and baghouse configurations. Removal efficiencies for beryllium and nickel were not determined due to analytical laboratory error. The removal efficiency for most trace metals is generally over 90 percent. Caution is required when reviewing the removal efficiency of antimony, since most of the antimony measurements were below detection limits. Mercury concentration was also low. Only trace levels of mercury, i.e. close to the method detection limits, could be detected in the baseline and parallel tests. The removal efficiency for mercury appears to fall in the 50%-95% range.

The GSA/ESP arrangement indicated average removal efficiencies of greater than 99 percent for arsenic, barium, chromium, lead and vanadium. Removal efficiencies are significantly less than 99 percent for antimony, manganese, mercury and selenium. Lower removals for mercury and selenium are expected because of the volatility of these metals.

The GSA/PJBH configuration showed 99+ percent removal efficiencies for arsenic, barium, chromium, lead, manganese, selenium and vanadium. Cadmium removal was much lower with this arrangement than any of the other arrangements in both baseline and demonstration tests. Mercury removal efficiency for this arrangement was lower than with the GSA/ESP arrangement.

The removal of HCl and HF was dependent on the utilization of lime slurry and was relatively independent of particulate control device configuration. The removal efficiencies ere greater than 98% and 96% for HCl and HF, respectively.

	GSA + ESP Series		GSA + ESP Parallel		GSA + FF Parallel		GSA + ESP + FF Series	
Parameter	Reported RE (%)	Total Uncertainty (%)	Reported RE (%)	Total Uncertainty (%)	Reported RE (%)	Total Uncertainty (%)	Reported RE (%)	Total Uncertainty (%)
Antimony	89.71	18.38	96.91	13.49	97.68	14.17	89.67	17.10
Arsenic	98.74	8.17	98.48	8.14	99.83	8.10	99.98	8.11
Barium	98.37	7.81	99.58	7.92	99.54	7.92	99.69	7.77
Cadmium	97.42	10.99	86.98	11.31	71.40	13.11	94.03	10.85
Chromium	99.09	8.63	98.14	9.24	99.46	9.23	99.65	8.47
Cobalt	98.38	9.55	98.24	9.52	98.68	9.51	98.66	9.51
Lead	98.79	9.47	97.36	9.16	99.51	9.16	99.69	9.35
Manganese	99.20	9.13	98.28	9.36	99.57	9.24	99.77	9.13
Mercury	79.15	38.24	66.38	11.71	31.97	527.49	94.45	14.26
Selenium	73.05	28.46	81.56	35.36	99.93	9.49	99.11	10.41
Vanadium	98.73	13.98	98.71	13.00	99.07	12.90	99.17	13.74
Particulate	99.59	9.70	99.52	4.16	99.86	4.16	99.90	9.70
HCl	---	---	---	---	7.71	478.82	-12.38	370.75
HF	---	---	---	---	22.08	488.02	-73.24	248.95

Table 3. Baseline Tests Removal Efficiencies and Uncertainties

	GSA + ESP Series		GSA + ESP Parallel		GSA + FF Parallel		GSA + ESP + FF Series	
Parameter	Reported RE (%)	Total Uncertainty (%)	Reported RE (%)	Total Uncertainty (%)	Reported RE (%)	Total Uncertainty (%)	Reported RE (%)	Total Uncertainty (%)
Antimony	84.72	37.99	98.78	14.24	98.65	14.20	95.01	18.59
Arsenic	99.96	8.37	96.36	47.79	99.98	8.24	99.99	8.37
Barium	99.63	8.80	92.72	90.19	99.49	9.44	99.74	8.81
Cadmium	98.68	10.77	93.27	64.71	78.63	20.31	97.37	11.73
Chromium	99.48	9.58	95.11	58.92	99.50	8.85	99.66	9.60
Cobalt	98.66	9.48	94.27	64.39	98.91	9.47	99.13	9.62
Lead	99.88	9.08	92.08	107.09	99.61	9.51	99.88	9.07
Manganese	92.44	33.45	95.58	53.68	99.13	10.18	99.87	9.67
Mercury	88.27	24.72	-38.89	1918.94	49.23	136.17	90.16	27.34
Selenium	76.87	88.86	99.81	10.34	99.80	10.32	99.96	10.18
Vanadium	99.18	13.87	93.37	75.62	99.00	12.50	99.46	13.90
Particulate	99.86	3.63	96.63	43.05	99.94	4.00	99.96	3.62
HCl	---	---	---	---	99.96	11.85	98.71	13.03
HF	---	---	---	---	96.82	14.67	98.99	12.81

Table 4. Demonstration Tests Removal Efficiencies and Uncertainties

XII. DEMONSTRATION RUN

28-day GSA/ESP Demonstration Run

The 28 day demonstration run, with GSA operating in conjunction with ESP only, started on October 25, 1993 and ended on November 24, 1993. This demonstration run began with the boiler burning the high-sulfur (2.7%), low-chloride Andalex coal and test conditions of: 320°F inlet flue gas temperature; 18°F approach-to-saturation temperature; 1.5 gr/acf fly ash injection; 0.12 percent coal chloride level; 20,000 scfm flue gas flow rate; and 30 rpm recycle screw speed. The SO_2 control mode was engaged for this run with an overall system SO_2 removal efficiency set-point of 91 percent. Due to some problems encountered in obtaining the test coal, a switch was made to burning a higher-sulfur (3.5%) coal for a period of time. The Ca/S ratio averaged 1.40 - 1.45 moles of $Ca(OH)_2$/mole inlet SO_2 during this demonstration run.

The demonstration run showed that all three of the major objectives were successfully achieved.

- The overall system SO_2 removal efficiency averaged 90-91 percent, i.e., very close to the set-point. The switch to the higher-sulfur coal demonstrated the flexibility of the GSA system

- The particulate removal efficiency was good at an average of 99.9+ percent, with an emission rate below 0.015 lbs/MBtu.

- The GSA system demonstrated the reliability of this technology by remaining on-line for the entire 28-day period that the boiler was operating.

14-day PJBH Demonstration Run

The purpose of the 14-day demonstration run was to demonstrate that the GSA system (reactor/cyclone/PJBH), as installed at the CER, could operate reliably and continuously, while simultaneously achieving 90+ percent SO_2 removal and maintaining the PJBH outlet emissions below the NSPS for particulates.

The specific design test conditions for this run were the same as those used for the previous 28-day GSA demonstration, except that the fly ash addition rate was reduced slightly from 1.5 to 1.0 gr/acf. This demonstration run was successfully completed in March 1994, and the following observations were made.

- The overall system (reactor/cyclone/PJBH) SO_2 removal efficiency averaged more than 96 percent during the entire 14-day demonstration run.

- The average Ca/S level during this run ranged from about 1.34 to 1.43 moles $Ca(OH)_2$/mole inlet SO_2.

- The PJBH particulate removal efficiency averaged 99.99+ percent. The emission rate was 0.001 to 0.003 lbs/MBtu.

XIII. ECONOMIC EVALUATION

Under the scope of this project, Raytheon Engineers & Constructors prepared an economic evaluation of the GSA FGD process using the same design and economic premises that were used to evaluate about 30-35 other FGD processes for the Electric Power Research Institute. The relative process economics for the GSA system were evaluated for a moderately difficult retrofit to a 300-MW boiler burning a 2.6 percent sulfur coal. The design SO_2 removal efficiency was 90 percent.

The resulting capital cost estimate (in 1990 dollars) is shown in Table 5 together with the estimate for the conventional wet limestone, forced-oxidation (WLFO) scrubbing system. The total capital requirement of $149/kW for the GSA process is substantially lower than the $216/kW for the WLFO system. The significant reduction in capital is primarily due to lower costs in the SO_2 absorption area.

Total Capital Investment Comparison
(1990 $, 300-MW, 2.6% S coal)

Area	GSA ($/kW)	WLFO ($/kW)
Reagent Feed	25	37
SO_2 Removal	38	71
Flue Gas Handling	18	24
Solids Handling	5	7
General Support	1	2
Additional Equipment	4	4
Total Process Capital	91	145
Total Capital Requirement	149	216

Table 5. Total Capital Investment Comparison

The levelized annual revenue requirements for the two processes (in 1990 dollars) are shown in Table 6. The levelized annual requirement for the GSA process is somewhat lower than that for the WLFO system. The principal operating cost for the GSA process is the cost of the pebble lime.

LEVELIZED COSTS
(300-MW, 2.6% S coal, 15-year levelizing)

	Mills/kWh	
Fixed Costs	**GSA**	WLFO
Operating Labor	0.52	0.66
Maintenance	1.49	1.74
Administrative and Support Labor	0.34	0.41
	2.35	2.81
Variable Costs		
Raw Material	1.82	0.65
Solids Disposal	0.86	0.57
Water	0.01	-
Steam	-	0.55
Electricity	0.47	1.16
	3.16	2.93
Fixed Charge (Capital)	5.40	7.30
Total	10.91	13.04

Table 6. Levelized Costs

XIV. COMMERCIALIZATION

One of the objectives of this demonstration project was for AirPol to establish its capability in designing, fabricating, and constructing the GSA system so that the demonstrated technology can be effectively commercialized for the benefit of the U.S. electric utility and industrial markets. The progress of this demonstration project matches very well with the development of the utility FGD market. The GSA technology is now being commercialized in order to meet the Phase II Clean Air Act Amendments (CAAA) compliance requirements.

During the course of designing the demonstration unit, an effort was made by AirPol to standardize the process design, equipment sizing, and detailed design so that the installation of a commercial unit can be accomplished within a relatively short time frame. Furthermore, equipment design was simplified, resulting in reduced material and construction costs. With the confidence that the GSA system is capable of achieving the required levels of performance, AirPol has developed a standard design of scale-up units.

The successful effort from the project has resulted in a commercial application in Ohio. AirPol has a GSA system for a 50 MWe municipal boiler burning Ohio coal as its first commercial utility installation in the United States. The state of Ohio, in conjunction with the Ohio Coal Development Office, awarded the city of Hamilton a grant to install a GSA system in the city's municipal power plant. In order to meet the requirements of the CAAA, it has been necessary to burn relatively expensive, low-sulfur coal in this plant. The installation of the GSA will allow the city to meet environmental regulations while using high-sulfur Ohio coal for power generation.

The pollution control equipment in existence at Hamilton was a hot-side electrostatic precipitator (ESP). This precipitator was undersized from inception, and never worked well. Several alternatives for this ESP were considered in connection with the installation of the GSA:

(1) Install the GSA upstream of the ESP and extend the unit to attain sufficient capacity.

(2) Use the ESP as primary dust collector upstream of the GSA with a new final dust collector

(3) Demolish the ESP and replace it with the GSA and new final dust collector

(4) Leave the ESP in place, de-energize it, and connect the GSA with final collector downstream

The fourth alternative was finally selected and the GSA was connected to the existing exhaust stack downstream of the ID fan. A long duct from the stack crosses a roadway and drops down and enters the GSA reactor. After passing through the reactor and cyclone, the flue gas enters a fabric filter of the pulse-jet type and continues to a new ID fan that returns the cleaned flue gas to the exhaust stack just above the point where it left to enter the GSA.

A lime preparation system adjacent to the GSA with lime silo, slurry tank with agitator, and a slurry pump produces a lime slurry of 20% concentration that is pumped to the reactor. The by-product collected in the fabric filter is gathered in screw conveyors and transported pneumatically to a by-product silo, from where it is removed by truck to landfill.

The technical data for the Hamilton installation are as follows:

Boiler Capacity	50 MWe
Type of Boiler	Pulverized Coal
Type of Coal	Ohio 3% + sulfur
Gas Volume	224,728 ACFM
Gas Temperature	320 °F
Moisture Content	7.8 % by Volume
Oxygen Content	4.6 % by Volume
Particulate Content	2 gr/SCFD
SO_2 Content	2,612 PPMd
SO_2 Removal	90 % Design

Another GSA installation for a fossil fuel boiler is being installed in Kaohsiung, Taiwan. The installation is in a sugar refinery where two oil fired boilers each have a dedicated GSA. The larger boiler has a steam generating capacity of 100 TPH, while the smaller one generates 35 TPH.
Both GSA units are equipped with fabric filters, dual ID fans, and a gas recirculating system. The reason for the dual fans and the recirculation is that both boilers have great load swings, and in order to attain the required SO_2 removal efficiency, the GSA must run with at least 50% of design gas volume. When the boiler capacity is reduced below the design capacity, a portion of the flue gas is recirculated via a separate fan from the outlet of the fabric filter to the inlet of the GSA reactor to maintain minimum design gas flow.

Both systems operate with hydrated lime, and calcium chloride is added from a storage tank in order to enhance the acid gas absorption. Due to the fact that the oil firing generates minimal amounts of particulates, by-product from the by-product silo is returned to the reactor to create particulate nuclei for lime slurry.

The cleaned flue gases from the two systems enter an existing masonry exhaust stack. Before the gases reach the stack they pass a steam heated coil that increases the gas temperature to reduce the visible steam plume from the stack.

The technical data for the two plants are as follows:

Boiler Steam Rating	100 TPH	35 TPH
Type of Fuel	Oil #6	Oil #6
Gas Volume	97,554 ACFM	27,748 ACFM
Gas Temperature	298 °F	280 °F
Moisture Content	13.36 % by Volume	3.5% by Volume
Oxygen Content	1.96 % by Volume	1.74 %by Volume
Particulate Content	2.4 gr/SCFD	2.3 gr/SCFD
SO_2 Content	510 PPMd	517 PPMd
SO_2 Removal	80 % Design	80 % Design

In addition to the Hamilton and Taiwan installations, approximately 20 GSA plants for refuse and hazardous waste incineration are in operation, most of them in Europe. Some of these installations have very sophisticated control equipment for NOx, furans, and dioxins with extremely low outlet concentrations.

XV. DISCLAIMER

Reference in this report to any specific commercial product, process, or service is to facilitate understanding and does not necessarily imply its endorsement or favoring by either DOE or TVA.

SMALL, MODULAR, LOW-COST COAL-FIRED POWER PLANTS FOR THE INTERNATIONAL MARKET

B. Zauderer, B. Frain, and B. Borck
Coal Tech Corp.
P.O. Box 154
Merion Station, PA 19066

A. L. Baldwin
U.S. Department of Energy
Pittsburgh Energy Technology Center
Pittsburgh, PA 15236

ABSTRACT

This paper presents recent operating results of Coal Tech's second generation, air cooled, slagging coal combustor, and its application to power plants in the 1 to 20 MW range. This 20 MMBtu/hour combustor was installed in a new demonstration plant in Philadelphia, PA in 1995. It contains the combustion components of a 1 MWe coal fired power plant, a 17,500 lb/hour steam boiler, coal storage and feed components, and stack gas cleanup components. The plant's design incorporates improvements resulting from 2000 hours of testing between 1987 and 1993 on a first generation, commercial scale, air cooled combustor of equal thermal rating. Since operations began in early 1996, a total of 51 days of testing have been successfully completed. Major results include durability of the combustor's refractory wall, excellent combustion with high ash concentration in the fuel, removal of 95% to 100% of the slag in the combustor, very little ash deposition in the boiler, major reduction of in-plant parasitic power, and simplified power system control through the use of modular designs of sub-systems and computer control. Rapid fuel switching between oil, gas, and coal and turndown of up to a factor of three was accomplished. All these features have been incorporated in advanced coal fired plant designs in the 1 to 20 MWe range. Incremental capital costs are only \$100 to \$200/kW higher than comparable rated gas or oil fired steam generating systems. Most of its components and subsystems can be factory assembled for very rapid field installation. The low capital, low operating costs, fuel flexibility, and compatibility with very high ash fuels, make this power system very attractive in regions of the world having domestic supplies of these fuels.

I. INTRODUCTION

This paper updates the results of work performed on Coal Tech's commercial scale 20 MMBtu/hour air cooled, slagging coal combustor since the last report at the 1995 Clean Coal Conference [1]. During the past year, a second generation, 20 MMBtu/hr combustor has been placed in operation in a coal combustion system. It incorporates all the features of Coal Tech's new low power cost, solid fuel plant. The central feature of this plant is an air cooling combustor whose wall heat transfer loss is recuperated to the combustion air, making this heat available to the thermodynamic cycle. A portion of the SO_2 and NO_x emissions are controlled inside the combustor, which is designed for new and retrofit boiler applications. Coal Tech's development of the air cooled combustor began in the late 1970's in a 1 MMBtu/hr air cooled, cyclone combustor [2], continued in the mid 1980's in a 7 MMBtu/hr water cooled, cyclone combustor [3], and was followed by 2000 hours of operation of a first generation, 20 MMBtu/hr, air cooled combustor between 1987 and 1994 [4-7]. The latter facility was located in an industrial heating plant in Williamsport, PA. Fuels tested include coal, coal water slurry, refuse derived fuel, oil, and gas. Test operations to 1991 were sponsored in part by the United States Department of Energy Clean Coal Technology Program [4].

Subsequent testing under another DOE sponsored project began in 1992 [5-7]. The first phase focused on improving combustor durability and combustor operation under automatic computer control. Several hundred hours of operation over a 7 month period in 1993 were implemented without requiring any internal refurbishment of the combustor walls.

The second phase of this project began in 1994 and is currently in progress. The results of prior testing were incorporated in the design of a new coal fired power plant using a second generation combustor rated at 20 MMBtu/hr and capable of generating up to 1 MW of electric power. The combustion parts of the plant were fabricated and installed in 1995 at an industrial site in Philadelphia, PA. The subsystems of the plant were designed to take advantage of the unique features of the air cooled combustor. This includes an oil design flat bottom boiler that was modified for real time removal of any ash or slag carried over from the air cooled cyclone combustor. It also includes a coal processing system that produces coarsely pulverized coal (50% passing 100 mesh compared to previous operation at 70% passing 200 mesh). This greatly reduces the capital and operating cost of the coal handling system. All the auxiliary subsystems, such as combustor cooling and combustion air supply, fuel supply, and cooling circuits were modularized to reduce capital cost and operating and maintenance costs. As part of this latter effort, the power requirements for the 20 MMBtu/hr combustor were reduced by two-thirds compared to the prior unit. Some features of this new plant were described at the Clean Coal Conference in Denver, CO in 1995 [1].

Test operations began in early 1996, and to date 51 days of testing have been completed. Results have substantially exceeded design performance. For example, the amount of bottom fly ash deposits in the boiler has been so low that its real time removal has not yet been necessary.

This paper summarizes the recent test results and discusses the use of this new design for low cost power plants in the 1 to 20 MWe range. This power system is especially attractive in regions with local deposits of high ash coals.

Coal Tech's Advanced Air Cooled, Cyclone Coal Combustor

The cyclone combustor is a high temperature (> 3000^{o}F) device in which a high velocity swirling gas is used to burn crushed or pulverized coal. Figure 1 shows a schematic of Coal Tech's patented, air cooled combustor. Gas and oil burners rapidly preheat the combustor and boiler during startup. Pulverized coal and powdered sorbent for SO_2 control are injected into the combustor in an annular region enclosing the gas/oil burners. Air cooling is accomplished by flowing combustion air through tubes on the outside of a ceramic liner in the combustor. This cooling air provides over 90% of the combustion air in the combustor, and it is introduced tangentially in a swirling manner into an annulus enclosing the fuel injection cylinder in the combustor, (see figure 1). The ash and reacted sorbent melt on the liner and the resultant slag is drained through a tap at the downstream end of the combustor.

Nitrogen oxide emissions are reduced by operating the combustor in a fuel rich mode, with final combustion taking place in the boiler. Operations in the first generation 20 MMBtu/hr combustor in Williamsport yielded, under optimum conditions, about two-thirds NO_x reductions to 0.26 lb of gas/MMBtu, or 200 ppm (at 3 % O_2) at about 70% of stoichiometric air/fuel ratio in the combustor and high combustion efficiencies. The stoichiometric ratio for the combustor/boiler was between 1.25 and 1.5. Sulfur emissions are controlled primarily by sorbent injection into the combustor. Measurement of SO_2 levels at the stack gas outlet from this previous boiler yielded average SO_2 reductions of 50% to 70%, and as high as 85%, with calcium hydrate injected into combustor at Ca/S mol ratios of 3 to 4. Particulate emissions were controlled in part by slag retention in the combustor. It was augmented with a wet particle scrubber which reduced the particle emissions to as low as 0.26 lb of solids /MMBtu.

II. THE SECOND GENERATION, 20 MMBTU/HR COMBUSTOR/BOILER PLANT IN PHILADELPHIA, PA

The design of this plant was based on the results of tests in the 20 MMBtu/hr air cooled combustor in Williamsport, PA, and on various site specific combustor applications studies for power plants in the 1 to 20 MW range that were performed in the past several years [6,7].

It was originally planned to install the 20 MMBtu/hr combustor/boiler at the new site with an atmospheric back pressure turbine to generate about 500 kW of power from the 17,500 lb/hr, 250 psig boiler. Sale of this power would partially defray the cost of more extensive durability tests on the combustor/boiler system. However, due to excellent progress this year in the combustor test effort, it was decided to eliminate the power generation step and proceed to commercial introduction of the technology.

To meet the particle emission standard for Philadelphia, a baghouse was required in place of the wet particle scrubber that was used in Williamsport. The latter's best performance resulted in a particle emission of 0.26 lb/MMBtu, which was below the Williamsport standard of 0.4 lb/MMBtu. The Philadelphia standard is 0.06 lb/MMBtu. The manufacturer of the baghouse has stated that particle emissions of less than 0.03 lb/MMBtu can be readily achieved under the operating conditions existing in the present facility.

Figure 2 is a side view of the new 20 MMBtu/hr combustor/boiler installation in Philadelphia. PA. Its total size is such that it can be shipped by tractor trailer to any site. Figure 3 shows a plan and side view of the Philadelphia facility. It includes provision for a 25 ton raw coal delivery and storage area,

Figure 1
Coal Tech's Air Cooled Combustor

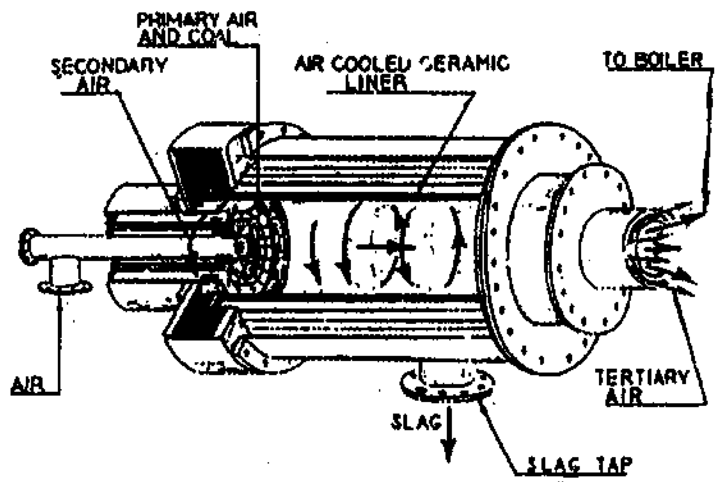
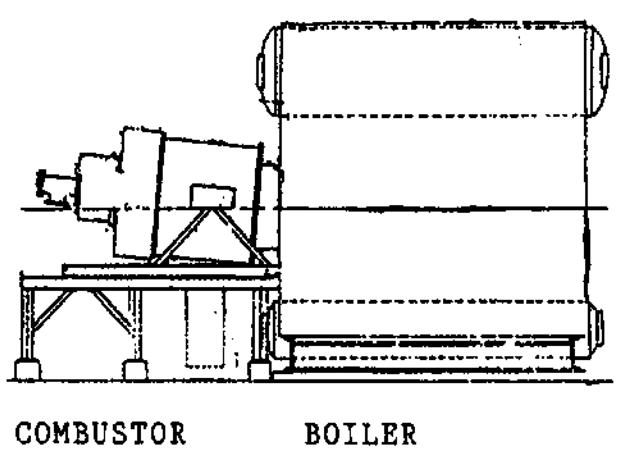


Figure 2:
20 MMBtu/hr Combustor-Boiler Installation at Philadelphia Plant



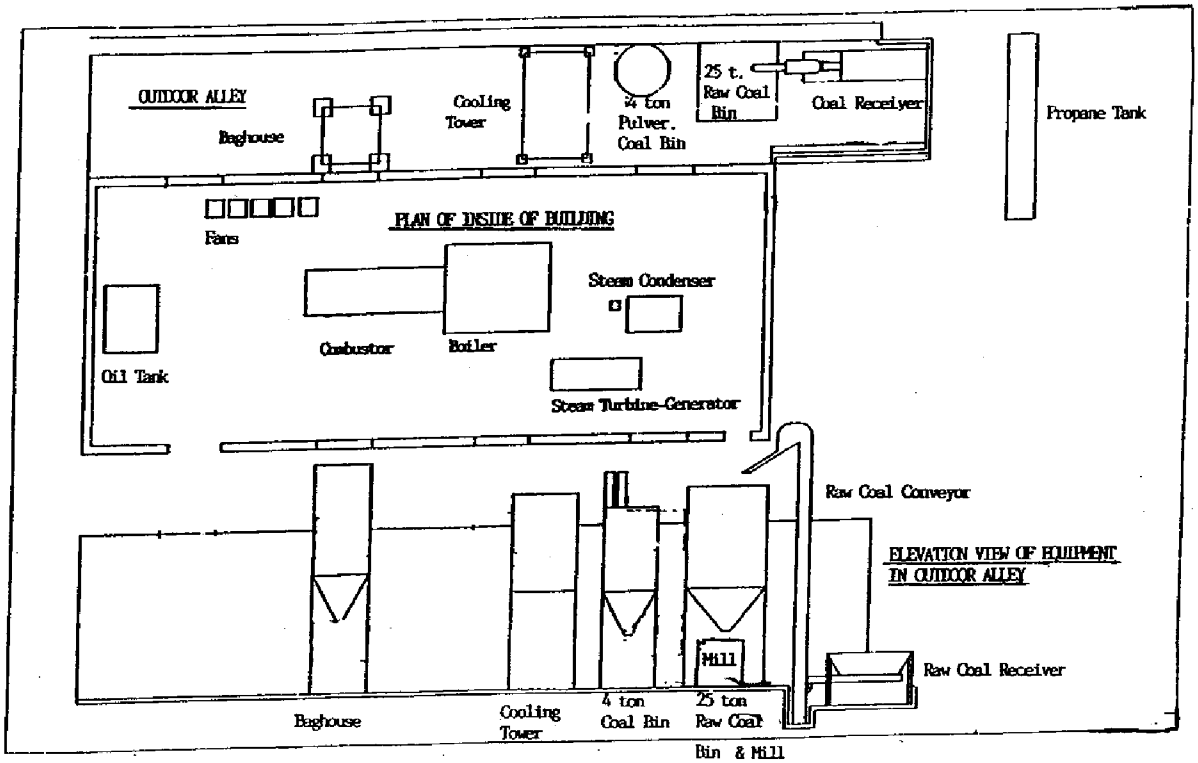


Figure 3: Plot Plan of the 20 MMBtu/hr Combustor-Boiler Test Site in Philadelphia.

a low cost coal mill, a 4 ton pulverized coal storage bin, sorbent storage bins, pneumatic coal and sorbent delivery, a boiler, the combustor and its auxiliary subsystems, specifically, water cooling, oil, gas, combustion air, cooling air, compressed air, slag removal, and the stack system, including the baghouse, and induced draft fan. The entire system is controlled by programmable logic controllers (PLC) and computer process control. Performance parameters are measured and recorded on a computer. Combustion gases, O_2, CO, NO_x, and SO_2, are measured in the boiler radiant furnace section, boiler stack outlet, and baghouse outlet. Novel Features and Operating Experience of the Second Generation Combustor/Boiler Facility.

The facility was designed to include the major features that will be incorporated in Coal Tech future commercial power plants in the 1 to 20 MWe range. Therefore, the primary design objective was to minimize capital, operating and maintenance costs.

Capital cost is minimized by factory assembly of major subsystems of the plant. Oil/gas designed boilers are compatible with the air cooled, coal combustor. These boilers are factory assembled for thermal ratings of up to 200 MMBtu/hr. Air cooled combustors can be fabricated up to 150 MMBtu/hr. The combustor's auxiliary subsystems are assembled in modules and attached to the combustor support structure. Therefore, the combustor and boiler can be shipped from the factory in two modules.

Another important capital cost saving results from the fuel flexibility and rapid shift among the various fuels. This sharply reduces the need for on site fuel storage.

Air cooling operation was much improved in the present combustor to the point where gas and oil fuel consumption for heatup and cooldown of the combustor was reduced by about a factor of two from the quantities used in the Williamsport combustor. Another major result of the improved air cooling was a factor of two reduction in the cooling fan power requirement. In addition, the quantity of compressed air flow required to operate the facility was sharply reduced. Finally, the use of a baghouse in place of the wet particle scrubber sharply reduced the induced stack fan power. As a result, the total power used in the Philadelphia plant was reduced to one-third of the level required in the first generation Williamsport facility.

The improved combustor operation reduced the combustion gas temperature at the boiler outlet an average of 100°F to 150°F for identical coal firing and sootblowing conditions in the previous combustor. Additional cooling of the stack gases was added to allow the use of substantially lower cost bags for the baghouse and to further reduce the stack fan power.

The combustor is a higher maintenance component than the boiler. It is, therefore, essential to minimize downtime when it requires refurbishment. Consequently, the current combustor design allows its removal from all its auxiliary sub-systems and from the boiler in less than 1 day.

A high maintenance item has been the combustor's slag tap assembly, primarily during the initial tests. Subsequent modifications were made which have sharply reduced maintenance to this item.
The relay controlled system used in the previous combustor system was replaced with programmable logic controllers (PLC). The PLC assure that the combustor's fuel supply and the boiler's steam

supply operate with all safety interlocks functioning. The previous computer process control software was upgraded to account for the changes in the design of the present combustor. As the test effort proceeded, it was found that the combustor could be controlled with a much simpler procedure than was used for the previous combustor, and the software was changed accordingly.

With these improvements, the personnel needed to operate the facility was reduced from an average of six used in the Williamsport facility to two or three, depending on the specific test objectives.. Based on this experience, it is anticipated that a fully commercial plant can be operated with substantially fewer personnel than are used in a conventional coal fired plant.

20 MMBtu/hr Combustor Operation in the Philadelphia Facility

As soon as the present combustor was placed into operation, its exhibited performance was far superior to the earlier unit. Areas of improvement include combustion efficiency, slag retention, wall materials durability, and length of heatup and cooldown.

Slag retention, which is a key measure of slagging combustor performance, improved substantially. In the earlier 20 MMBtu/hr combustor, only one-half to two-thirds of the injected coal ash and sorbent minerals was converted to slag in the combustor. The balance of the ash and sorbent was blown out of the combustor as dry fly ash. Furthermore, over one-half of the slag formed in the combustor flowed out of the exit nozzle to the boiler floor, thus limiting the run time of the combustor. Although provision has been made to remove slag carryover from the combustor to the boiler by installing a combustor/boiler transition section, in the operations to date, the amount of slag carried over from the combustor to the boiler ranged from 0% to 5% of the total slag. Slag retention was also substantially better than before, averaging two-thirds of the injected mineral matter, which includes coal ash and sorbents.

Combustor refractory liner durability is another major performance parameter. Chemical reactions between the liquid slag and the combustor refractory wall can rapidly deplete the latter. However, by control of the combustor wall temperature, a layer of frozen slag can form on the combustor's refractory wall which maintains the integrity of the wall. Much progress had been made in perfecting this wall replenishment technique in the earlier 20 MMBtu/hr combustor. Replenishment of the refractory liner by injection of fly ash with the coal and sorbent proved to be very effective in the earlier combustor. In the present combustor, the combustor wall replenishment procedure has been further improved. Consequently, it has not been necessary to reline the combustor wall with refractory in the operations to date.

The cooling and combustion air distribution and control scheme was substantially modified for the present combustor in order to simplify the combustion and combustor wall cooling process. The new scheme has proven to be much simpler to control , and the need for the previous complicated computer control has been eliminated.

To minimize nitrogen oxide emissions it is necessary to operate the combustor under fuel rich conditions. Final combustion occurs in the furnace section of the boiler where the CO and H_2 rich combustor gas exhaust is mixed with additional air to complete combustion. Optimum No_x reduction occurs at about 70% stoichiometric air/fuel ratio in the combustor. [3,4]. However, operation of the earlier 20 MMBtu/hr combustor at this condition resulted substantially reduced combustion efficiency [3,4].

The three methods of measuring combustion efficiency in the slagging combustor are based on carbon in the slag, CO in the stack gases, and carbon in the stack fly ash. Under fuel rich conditions, significant amounts of carbon in the slag indicates poor combustion inside the combustor. In the present combustor, combustion efficiency, based on carbon in the slag, has been over 99% in almost all the tests including at fuel rich operation as low as 75% stoichiometric air/fuel ratio. Since carbon monoxide is an air pollutant, it is essential that it be minimized in the combustion process. The CO concentration in the stack was generally in the 200 ppm range which corresponds to better than 99% combustion efficiency.

Both these measurements of combustion efficiency do not account for unburned carbon that is carried over to the stack baghouse. Due to the difficulty in obtaining real time sampling of the baghouse fly ash, the carbon content in the fly ash was determined from random grab samples taken from all the ash collected on the day of testing. The carbon content of the ash ranged from 20% to 50% (dry basis). Since on average about one-third of mineral matter injected reported to the baghouse, one can compute the conversion of the solid carbon in the coal to CO2 and CO in the combustor from the amount of unburned carbon in the baghouse fly ash. This yielded a carbon conversion greater than 90% for most of the tests. In several tests small quantities of fly ash in the stack were collected in a filter. Analysis of the carbon content in one of these tests yielded a carbon conversion of 94%.

The stoichiometric ratio in the combustor (SR1) ranged from fuel rich to fuel lean (0.75<SR1< 1.1). Final combustion air was added at the combustor outlet into the boiler which yielded a stoichiometric ratio in the boiler furnace (SR2) in the range from 1.3 to 1.8.

Several bituminous coals were tested having higher heating values (HHV) in the range of 12,000 to 13,700 Btu/lb, ash contents in the 11% to 15% range, and sulfur contents in the range from 1.18% to 3.7%. The bulk of the tests were performed with 3+% sulfur coal.

The initial test effort this year has been focused on overall combustor performance, with lesser emphasis on SO_2 and NO_x control. The most recent tests have focused on SO2 control and excellent results have been achieved, especially in low sulfur coal. The analysis of these data is incomplete, and the results will be presented at the Conference. Both limestone and hydrated lime were injected into the combustor for slag conditioning and sulfur removal. Previous results in the 20 MMBtu/hr combustor in Williamsport showed that limestone was much less effective than calcium hydrate for sulfur capture. With calcium hydrate injection into the previous combustor, excellent sulfur capture results were achieved, where a maximum reduction in the 85% range was measured [5,7].

The degree of sulfur capture in the present combustor was found to be very sensitive to combustion conditions, the method and quantity of sorbent injection, and the mineral matter injection rate. In recent tests at high slag mass flow rates firing 3+% sulfur coal, SO_2 reductions measured in the end wall of the boiler furnace and in the boiler gas outlet at the stack were in the range of 60% to 75% at Ca/S mol ratios of under 3. Similar reductions were measured with injection of calcium hydrate into the boiler furnace near the combustor gas inlet to the boiler. In this case, the Ca/S mol ratios were in the range of 3.5 to 4.9. However, in the latter case, a substantial amount of the hydrate fell to the floor of the boiler furnace. Therefore, the Ca/S mol ratio is not an accurate measure of calcium utilization in this case.

In very recent tests with 1.5% sulfur coal, the SO_2 reductions were substantially higher. Reductions in the range of 75% to as high as 95% were measured. When expressed in lb/MMBtu, SO_2 emissions as low as 0.22 lb/MMBtu were measured. This is well below the 0.5 lb/MMBtu SO_2 emission standard for Philadelphia, and it near the 0.2 lb/MMBtu that is one of the current test objectives. The reductions were higher at the end wall of the boiler furnace than in the stack at the outlet of the boiler. No conclusive explanation for this behavior has been found. It is suspected the higher SO_2 at the boiler outlet may due to blowby of combustion gases through gaps in between the boiler tubes on the convective tube side of the boiler. This reduces the reaction time of sorbent with combustion gas in the boiler furnace. This matter should be clarified when all the data are analyzed.
One interesting result has been finding relatively high sulfur concentrations (10% to 20%) in the slag in several of the tests. With high slag mass flow rates, as obtained with high ash coals or by injecting additional ash, it may be possible to encapsulate all the coal sulfur in the slag. Tests in which additional metal oxide powder was injected into the combustor at up to 40% injected mineral mass flow rates have been very recently completed. The analysis of the resultant slags is not yet complete.

NO_x emissions are controlled by operating the combustor fuel rich. Maximum reductions to as low as 0.26 lb/MMBtu were measured in the previous combustor at stoichiometric ratio (SR1) in the range of 0.7. In the present combustor, the tests were performed at less fuel rich conditions. At slightly fuel rich conditions, the NO_x, (reported as NO_2) has been in the range of 0.36 to 0.7 lb/MMBtu. The 0.36 lb/MMBtu value was measured at SR1 equal to 0.9.

The above discussion presents a general overview of the performance of the present second generation 20 MMBtu/hr combustor. Its performance has been found to be superior to the previous combustor, especially in the areas of combustion efficiency, slag retention and removal from inside the combustor, durability of the internal combustor wall, and simplicity of control and operation. Considerable data on SO_2 on NO_x control have been measured, but the analysis is not complete. Based on the results obtained to date, the best results achieved in the current combustor (namely SO_2 reductions to 0.22 lb/MMBtu and NO_x reduction to 0.36 lb/MMBtu) match those measured in the prior unit (SO_2 reductions to 0.34 lb/MMBtu and NO_x reduction to 0.26 lb/MMBtu).

III. APPLICATION OF THE AIR COOLED SLAGGING COMBUSTOR TO 1 TO 20 MWe POWER PLANTS

The present second generation combustor facility was designed as a prototype for a low cost, modular, coal fired commercial power plant. As such, considerable attention was given to incorporate novel designs for all the components of the present facility in order to minimize cost. Key elements in the plant that result in cost saving are:

- The air cooled, coal combustor is compatible with compact boilers designed for oil firing, which have about one-half the volume of conventional coal fired boilers.
- Modular design of the combustor and its auxiliary subsystems.
- Fuel flexibility and rapid switching between fuels, which minimizes the need for on-site fuel storage, especially bulky coal storage.
- Optimization of stack gas particulate control system to minimize baghouse cost, and stack fan power.
- Combustion of coarsely pulverized coal to allow use of low cost coal mills.
- Automated microprocessor control of the plant.

All these factors were incorporated in the design of the present facility in Philadelphia. The best way of demonstrating the cost impact of a power plant based on Coal Tech's combustion system technology is to compute the incremental cost of this plant versus a comparable size gas or oil fired plant. The additional components/subsystems required by the Coal Tech plant are coal storage, processing, and feed systems, the air cooled combustor, the stack gas cleanup system, additional fans and blowers, and additional controls. All these items use Coal Tech designs that optimize performance and cost. The gas and oil fuel components and storage are used only for startup, cooldown and emergencies. Therefore, their thermal rating and fuel consumption is a only a few percent of the total energy used by the coal fired plant. In computing the added cost of this coal plant versus a conventional oil or gas plant, the incremental cost of the oil/gas burners and oil/gas storage and delivery components in the latter plant must be subtracted from the cost of the coal system. All power generation components, including the steam loop, generators, electric power distribution, such as turbine-generator, electric power distribution, are common to both plants.

A series of cost estimates were developed for several thermal ratings ranging from 20 MMBtu/hr to 125 MMBtu/hr. One combustor at 125 MMBtu/hr can produce about 10 MWe. Two combustors at this rating are attached to one boiler yield 20 MWe. For a steam generating plant only, the incremental cost of this coal plant over a conventional oil/gas plant is in the range of $10 to $25/lb/hr of steam, with the cost decreasing as the thermal rating increases. For a power plant, this incremental cost is in the $100 to $200/kW range.

The following example shows the economic benefit of this system. For a 125 MMBtu/hr coal fired steam plant with this combustor an incremental cost of $14/lb/hr of steam is obtained. Applying this to 7000 hour/year operation, a coal-oil or gas cost differential of $0.85/MMBtu, a 10%-90% equity-debt ratio, and a 4 year amortization, one obtains an internal rate of return (IRR) of **43%.** For the smallest plants, a higher coal-oil/gas differential is required to yield a similarly high IRR. The low cost of this coal fired power technology allows great flexibility in achieving excellent rates of return.

This technology is especially attractive for the international market in regions with domestic coal reserves but no domestic oil or gas reserves. In this case additional factors enter in the power plant analysis, such as import restrictions on clean fuels. The compatibility of this combustor with high ash fuels which are readily found in many international markets, further adds to the attractiveness of this technology. In the first generation combustor, operations with additional ash injection to 50% mineral matter was successfully implemented [5,7]. In the current combustor the total mineral matter injection rate has to date been as much as 40% of the total solid fuel injected.

IV. CONCLUSIONS

The results of the effort to date on the second generation 20 MMBtu/hr air cooled, slagging coal combustor facility have confirmed the performance and economic benefits of this technology. Very rapid progress in the test effort since the facility became operational at he beginning of 1996 have accelerated its commercial development schedule.

The compact and modular design of the plant in the 1 to 20 Mwe range allows factory fabrication and assembly of its subsystems and shipment of the modules to the site for rapid assembly. These features makes it attractive for steam and power generation at industrial sites in the US and overseas.

V. ACKNOWLEDGMENTS

Current test efforts are supported in part by the DOE-Advanced Combustion Technology Program at the Pittsburgh Energy Technology Center (PETC). Mr. Frank Shaffer is the Department of Energy/Pittsburgh Energy Technology Center's Technical Project Manager.

VI. REFERENCES

1. B. Zauderer, R. Frain, K. Peng, and B. Borck, "Demonstration of the Air Cooled Slagging Combustor on a 500 kW Coal Fired Power Plant",, in Proceedings 4th Annual Clean Coal Technology Conference, Denver, CO, Sept., 1995
2. C.S. Cook, Ed., "Evaluation of Closed Cycle MHD Power", DOE Contract Report No. DE-AC01-78-ET-10818, November 1981.
3. B. Zauderer, E. S. Fleming,"Experiments in NO_x and SO_2 Control in a Cyclone Combustor", 6th International Workshop on Coal Liquid and Fuels, Halifax, N.S., October 1986.
4. B. Zauderer, E. S. Fleming, "The Demonstration of an Advanced Cyclone Coal Combustor with Internal Sulfur , Nitrogen, and Ash Control., Vols. 1-3, Coal Tech Corp., August 1991. (NTIS DE92002587 & DE92002588T)
5. B. Zauderer, E. S. Fleming , "Development & Testing of an Industrial Scale, Coal Fired Boiler Slagging Combustor System", in <u>Proceedings 10th Annual Coal Preparation,</u>

Utilization, & Environmental Control Conference, (DOE/PETC, Pittsburgh, PA, July, 1994)

6. B. Zauderer, R. Frain, K. Peng, and B. Borck, "Development & Testing of an Industrial Scale, Coal Fired Boiler Slagging Combustor System", in Proceedings 11th Annual Coal Preparation, Utilization, & Environmental Control Conference, (DOE/ PETC, Pittsburgh, PA, July 12, 1995)

7. B. Zauderer, E. S. Fleming, B. Borck, and C. A. Smith, "Coal Tech's Air Cooled Slagging Combustor-Recent Developments", in Proceedings 3rd Annual Clean Coal Technology Conference, Chicago, IL, Sept.7,1994

CHIYODA THOROUGHBRED CT-121 CLEAN COAL PROJECT AT GEORGIA POWER'S PLANT YATES

PHASE II RESULTS

David P. Burford
Project Manager

Southern Company Services, Inc.
44 Inverness Parkway / Suite 230
Birmingham, Alabama 35242

ABSTRACT

The Chiyoda Thoroughbred CT-121 flue gas desulfurization (FGD) process at Georgia Power's Plant Yates completed a two year demonstration of its capabilities in late 1994 under both high- and low-particulate loading conditions. This $43 million demonstration was co-funded by Southern Company, the Electric Power Research Institute and the DOE under the auspices of the U.S. Department of Energy's Round II Innovative Clean Coal Technology (ICCT) program.

The focus of the Yates Project was to demonstrate several cost-saving modifications to Chiyoda's already efficient CT-121 process. These modifications included: the extensive use of fiberglass reinforced plastics (FRP) in the construction of the scrubber vessel and other associated vessels, the elimination of flue gas reheat through the use of an FRP wet chimney, and reliable operation without a spare absorber module.

This paper will focus on the testing results from the last trimester of the second phase of testing (high-ash loading). Specifically, operation under elevated ash loading conditions, the effects of low- and high-sulfur coal, air toxics verification testing results and unexpected improvements in byproduct gypsum quality are discussed.

I. INTRODUCTION

The demonstration at Georgia Power's Plant Yates involved the retrofit construction of a CT-121 wet-limestone scrubber to an existing 100 MW pulverized coal-fired boiler. The principle difference between the CT-121 process and more common spray tower-type FGD systems is the use of a single process vessel, Chiyoda's patented Jet Bubbling Reactor® (JBR), in place of the usual spray tower/reaction tank/thickener arrangement. Initial startup of the process occurred in October 1992, and the demonstration project was completed in December 1994. Process operation continues with the CT-121 scrubber as an integral part of the site's Phase I Clean Air Act compliance plan.

Several of the latest evaluations that comprised the CT-121 demonstration project are discussed in this paper. In the last trimester of testing the CT-121 process was operated under moderate-ash inlet loading conditions while process reliability and availability were continuously evaluated. Additionally, exceptional concurrent particulate removal efficiencies were measured under moderate-particulate loading conditions, which was consistent with particulate removal efficiencies observed in earlier measurements under both high- and low-particulate loading conditions.

Parametric testing was also conducted under moderate-ash loading conditions while burning both high- and low-sulfur coals. The data gathered were regressed and multi-variable regression models were developed to provide an accurate prediction of the scrubber's SO_2 removal efficiency under the most likely future operating conditions. As part of the moderate-particulate removal evaluation, limited air toxics measurements were also performed for the second time. The purpose of this additional testing was to evaluate air toxics removal across the CT-121 under elevated ash loading conditions as well as to validate or controvert the findings of an earlier air toxics testing effort that was sponsored by DOE in June of 1993[1].

A brief discussion of findings on the properties of the gypsum stack (not contaminated with flyash) following one year of dormancy is also included in this paper. An analysis of the chloride content showed that chloride levels in the gypsum decreased over time without any specific action by the project team. This finding increases the possible uses of the unwashed gypsum produced by this process. An indicator of public acceptance was the granting of a Plant Food License to Georgia Power for the non-ash gypsum at Plant Yates, by the State of Georgia’s Department of Agriculture in October of 1996.

In general, the Yates CT-121 process performed well, exhibiting excellent SO_2 removal efficiency, particulate removal and consistent reliability. In addition to these successes, several possible process improvements were identified during the demonstration that could improve future designs of an already superior process.

II. FACILITY AND OPERATING DESCRIPTION

The Yates plant site is comprised of seven coal-fired boilers, all Phase I affected units, with a total rated capacity of 1,250 MW. Plant Yates’ 100 MW Unit 1 is the source of flue gas for the CT-121 process. All of the flue gas from Unit 1 is treated by the CT-121 wet FGD process with no provision for flue gas bypass. During the low flyash phase of parametric testing in 1992 and 1993, the existing ESP for Unit 1 was used for particulate control. The design efficiency for this ESP is 98%. In March, 1994, the ESP was fully deenergized at the start of high-particulate parametric testing, and partially energized to a target efficiency of 90% between June 1994 and November 1994.

A simplified site diagram for the Yates CT-121 retrofit is presented in Figure 1.

The scrubber demonstration facility equipment can be divided into five major subsystems:

- Boiler / ESP
- CT-121 scrubber / wet chimney
- Limestone preparation circuit
- Byproduct gypsum stacking area
- Process control system.

The central feature of the process is Chiyoda's unique absorber design, called a Jet Bubbling Reactor (JBR), which combines concurrent chemical reactions of limestone dissolution, SO_2 absorption/neutralization, sulfite oxidation, gypsum precipitation and gypsum crystal growth together in one vessel. A cut-away view of the JBR is illustrated in Figure 2. Since much of the undesirable crystal attrition and secondary nucleation associated with the large centrifugal pumps in conventional FGD systems is eliminated in the CT-121 design, large easily dewatered gypsum crystals are consistently produced. This design also significantly reduces the potential for gypsum scale growth, a problem that frequently occurs in natural-oxidation FGD systems.

In the Yates installation (Figure 1), the flue gas enters the scrubber's inlet gas cooling section down-stream of the boiler's induced draft (I.D.) fan. This fan also serve as the scrubber's booster fan. Here the flue gas is cooled and saturated with a mixture of pond water and JBR slurry. From the gas cooling section, the flue gas enters an enclosed plenum chamber in the JBR formed by the upper deck plate and lower deck plate. Sparger tube openings in the floor of the inlet plenum force the inlet flue gas below the level of the slurry reservoir in the jet bubbling zone (froth zone) of the JBR as shown in Figure 3. After bubbling through the slurry, where all the concurrent reactions occur, the gas flows upward through large gas riser tubes that bypass the inlet plenum. Entrained liquor in the cleaned gas disengages in a second plenum above the upper deck plate due to a drastic velocity reduction and the cleaned gas passes to the 2-stage, chevron-style, horizontal-flow mist eliminator, then on to a wet FRP chimney.

"A closed-circuit, wet ball mill limestone preparation system is used to grind raw (3/4x0) limestone. The particle size of the ground limestone is small enough (90% passing a #200 mesh screen) to ensure that it is dissolved easily and that the amount of unreacted limestone in the JBR can be minimized or eliminated.

The JBR slurry reservoir provides about 36 hours of solid-phase residence time, depending on the SO_2 pick-up rate. The slurry from the JBR is pumped intermittently to a gypsum slurry transfer tank (GSTT) for JBR slurry level control and slurry density control. In the GSTT, the slurry is diluted for pumping to a Hypalon®-lined gypsum (or gypsum/ash) stacking area for gravity dewatering and storage. Gypsum stacking is a disposal technique that involves filling a diked area with slurry for gravity sedimentation. Over time, this area fills with settled solids. The filled area is then partially excavated to increase the height of the containment dikes. The repetitive cycle of

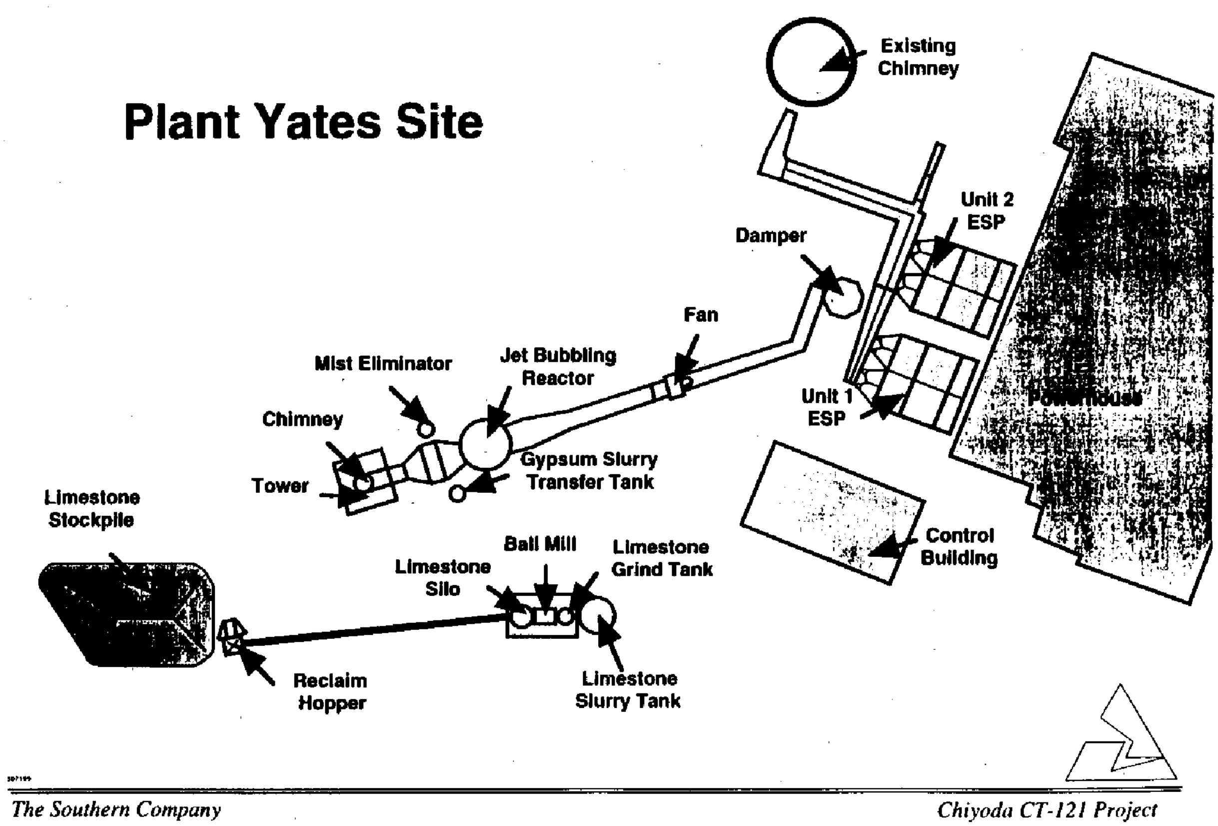


FIGURE 1

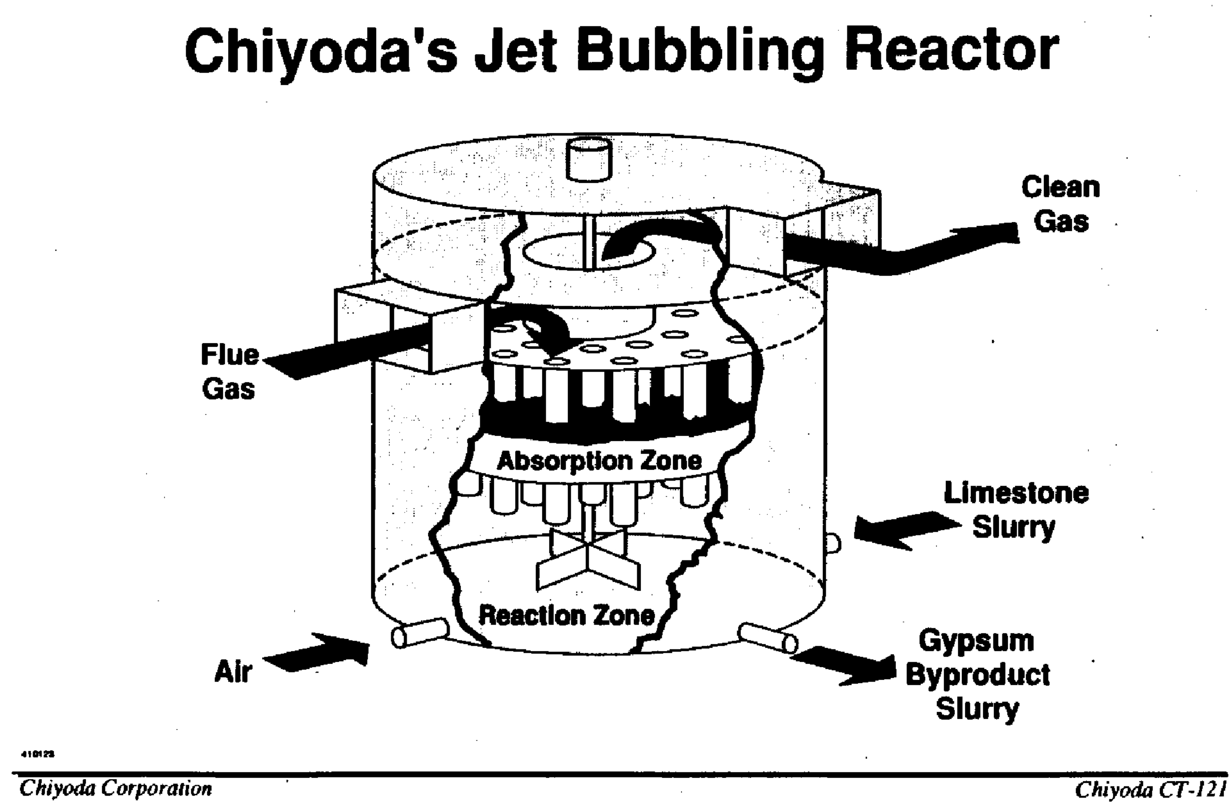


FIGURE 2

CT-121 Gas Sparger Action

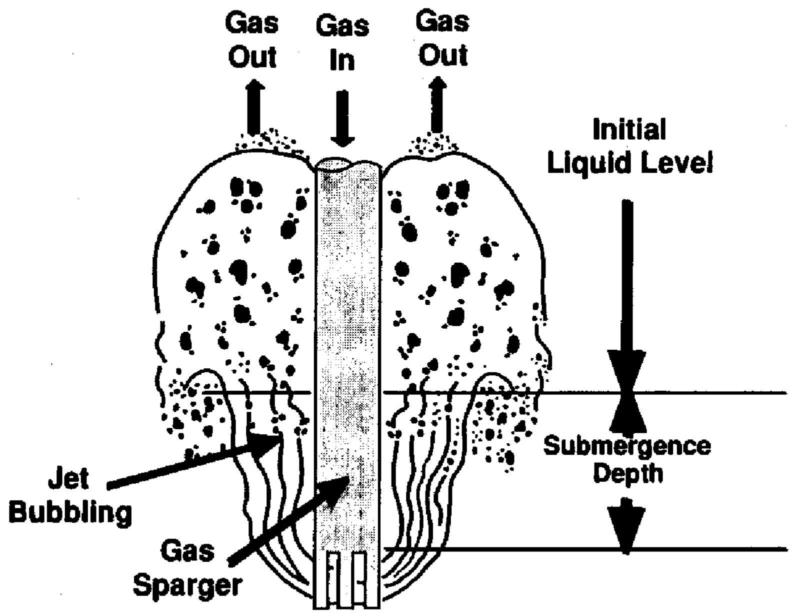


FIGURE 3

sedimentation, excavation, and raising of perimeter dikes continues on a regular basis during the active life of the stack. Process water is naturally decanted, stored in a surge pond and then returned to the CT-121 process. There is no blowdown or discharge from the Yates CT-121 process.

During normal operation of the FGD system, the amount of SO_2 removed from the flue gas is controlled by varying the JBR pressure drop (ΔP) or slurry pH. However, changing ΔP is easier and quicker to respond to changing conditions since it is done by adjusting the JBR liquid level. Higher liquid levels result in increased SO_2 removal because of increased contact time between the incoming flue gas and the scrubbing slurry. The pH can also be varied to affect SO_2 removal with higher pH resulting in increased removal efficiency. Boiler load and flue gas SO_2 concentration also affect removal efficiency, but are less controllable.

One of the most unique aspects of the CT-121 installation at Plant Yates is the wide use of fiberglass reinforced plastics (FRP) in several of the vessels to avoid the traditional corrosion damage associated with closed-loop FGD systems. Two of the vessels (the JBR and the limestone slurry storage tank) were constructed on site since their large size precluded shipment. The JBR inlet transition duct, where the flue gas is cooled prior to contacting the sparger tubes as a wet-dry interface, is also made completely of FRP. The inlet transition was discovered to be an area susceptible to erosion during high ash testing but homogeneous appliqué filler materials, Duromar® and Duromix®, now offer robust protection to exposed FRP surfaces at Plant Yates. A distinct advantage of the FRP construction was that it eliminated the need for a flue gas prescrubber, traditionally included in flue gas scrubber systems to remove chlorides that cause significant corrosion in alloys (fiberglass is mostly unaffected by inorganic acid attack and chlorides).

III. PROJECT OBJECTIVES

To evaluate the effectiveness of the Yates CT-121 design advances, the following test objectives of the two year demonstration program were established:

- Demonstrate long-term reliable operation of the CT-121 FGD system;
- Evaluate particulate removal efficiency of the JBR and system operation at normal and elevated particulate loadings;
- Correlate the effects of pH and JBR gas-side pressure drop (ΔP) onsystem performance;
- Correlate the effect of limestone grind on system performance;
- Evaluate the impact of boiler load on system performance;
- Evaluate the effects of alternate fuels and reagents on system performance;
- Evaluate equipment performance and construction material reliability; and
- Monitor solids properties, gypsum stack operation and possible impacts of the gypsum stack on ground water.

Many of these objectives were investigated during this last trimester of the second phase of the demonstration project, also known as the High-Particulate Auxiliary Test block. Two of the test periods in this test block provided data relevant to the focus of this paper:

- High-Particulate Alternate Coal Tests which evaluated scrubber performance under elevated particulate loading conditions while burning high-sulfur (3.4%) coal;
- High-Particulate Alternate Limestone Tests which evaluated an alternate limestone reagent source, while under elevated particulate loading, burning low-sulfur coal (1.2 % S).

Particulate and air toxics removal testing were also conducted during the Alternate Limestone testing. The data from the parametric portion of this test period was regressed to develop a predictive performance model for the conditions at which the testing was conducted, since these conditions are the most likely scenario for post-demonstration operation

IV. RESULTS

The CT-121 scrubber at Plant Yates continued to prove itself a very viable and cost effective technology for use in Clean Air Act, Title IV compliance. It exhibited excellent availability, maintained greater than 97% limestone utilization, and demonstrated the ability to exceed 98% SO_2 removal efficiency with high sulfur coal, while at maximum boiler load. The flexibility of the CT-121 process was also demonstrated through the use of a wide range of coals, varying from 1.2% to 4.3% sulfur content.

Operating Statistics

The duration of the demonstration, including the startup and shake-down phase, was 27 months, or approximately 19,000 hours. The low-particulate test phase (including shake-down) consisted of 11,750 hours, during which time the scrubber was operated for 8,600 hours. The remaining 7,250 hours of the demonstration included 5,510 hours of operation at elevated particulate loading. Complete operating statistics for the entire demonstration project are detailed in Table 1. The "high-ash" test period actually consisted of a high-ash loading period (during the Parametric Test block) in which the ESP was completely deenergized, and a moderate-ash loading period (during the Long-Term and Auxiliary Test blocks) during which the ESP was partially de-energized to simulate a more realistic scenario: a CT-121 retrofit to a boiler with a marginally performing particulate collection device. The moderate-ash loading condition resulted in better availability than did the high-ash loading condition.

	Low-Ash Test Phase	High-Ash Test Phase	Demonstration Project Duration *(Cumulative)*
Total Hours in Test Period	11,750	7,250	19,000
Scrubber Available Hours	11,430	6,310	18,340
Scrubber Operating Hours	8,600	5,210	13,810
Scrubber Called Upon Hours	8,800	5,490	14,290
Reliability[1]	**0.98**	**0.95**	**0.96**
Availability[2]	**0.97**	**0.95**	**0.97**
Utilization[3]	**0.73**	**0.72**	**0.75**

1. Reliability = Hours scrubber operated divided by the hours called upon to operate.
2. Availability = Hours scrubber available divided by the total hours in the period.
3. Utilization = Hours scrubber operated divided by the total hours in the period.

Table 1. Summary of Operating Statistics

Effect of Inlet SO_2 Concentration

The SO_2 removal efficiency of the scrubber was measured under five different inlet SO_2 concentration ranges; three during this most recent testing. The coal burned by Unit 1 for a majority of the testing was a blend of Illinois No.5 and No.6 bituminous coal that averaged 2.4% sulfur (as burned), except for a brief, unplanned period when 3.0% sulfur coal was burned. A 4.3% sulfur bituminous coal was burned during the Low-Particulate Alternate Coal Test block, and a 3.8% sulfur coal was burned for the High-Particulate Alternate Coal Test block. The High-Particulate Alternate Limestone Test (last test of the demonstration project) coincided with Plant Yates' compliance-driven transition to a low sulfur coal (approximately 1.2% S). This provided the scrubber project an opportunity to evaluate a fifth coal source.

The effect of inlet SO_2 concentration on SO_2 removal efficiency is quite significant. Figure 4 illustrates the decrease in SO_2 removal as inlet SO_2 concentration increased for the coal sources evaluated. Performance of the scrubber was outstanding during the low-sulfur coal burn. It should be noted that the low-sulfur coal tested limited the JBR pH to a maximum of 3.8 because of Aluminum-Fluoride-inhibited limestone dissolution (Al-F blinding). The Al-F blinding stems from the low-ionic strength of the scrubbing liquor, the elevated ash loading to the JBR and the coal trace metals concentrations. A maximum operating pH of 3.75 was chosen to ensure that near-complete limestone utilization was maintained in the scrubber. The test data from 1000 ppm (inlet SO_2 concentration) operations indicates that SO_2 removal efficiency did not decline at a slightly lower pH.

The evaluation of five different inlet SO_2 concentrations demonstrates the flexibility of the CT-121 process as well as it's exceptional SO_2 removal capability, even when burning fuels with a very high sulfur content. This is even more impressive considering that the maximum designed sulfur

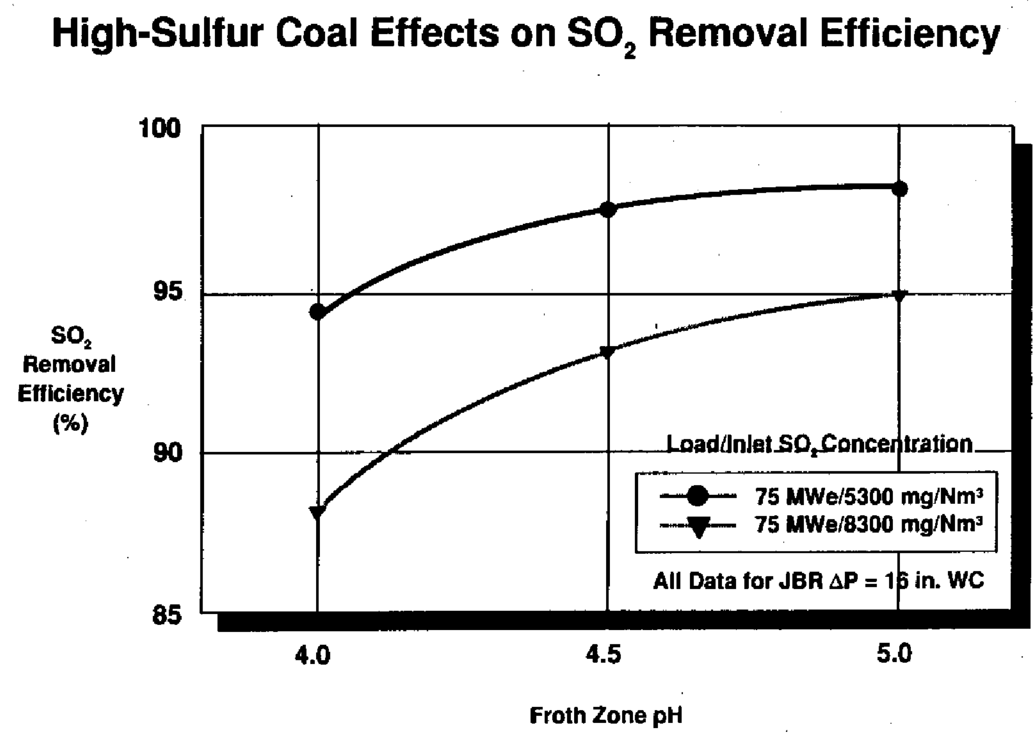

High-Sulfur Coal Effects on SO_2 Removal Efficiency
100
95
90
85
SO_2 Removal Efficiency (%)
Load/Inlet SO_2 Concentration
75 MWe/5300 mg/Nm³
75 MWe/8300 mg/Nm³
All Data for JBR ΔP = 16 in. WC
4.0
4.5
5.0
Froth Zone pH
410123

FIGURE 4

content for the demonstration unit was only 3.0%, and that this limit was exceeded by 43% in one test period. Other test data shows that even higher SO_2 removal efficiencies are achievable at higher pH values.

Particulate Removal Efficiency

Because of the torturous path taken by the flue gas during treatment in the JBR, an effort was made to quantify particulate removal. Consequently, the ability of the CT-121 process to remove flyash particulate was evaluated several times throughout the demonstration. Particulate loading measurements were made at the inlet and outlet of the scrubber under three different conditions of inlet mass loading, summarized in Table 2. The discussion here will focus on the particulate removal capabilities of the scrubber under only the moderate-ash loading conditions.

Condition	**ESP Energization**	**ESP Collection Rate**	**ESP Outlet→JBR Inlet** ***JBR Inlet Mass Loading (lb/MMBtu)***
1	Full	High	***Low (0.02-0.10)***
2	Partial	Moderate	***Moderate (0.20-0.50)***
3	Off	Low	***High (5.00-5.50)***

Table 2. ESP Configuration during Particulate Testing

Measurements of particulate removal across the JBR (Condition 2, Table 2) were made near the minimum and maximum nominal boiler loads (50 and 100 MW), and at low and high JBR ΔP settings (10 and 18 in.WC). The test conditions and results are shown in Table 3. As shown in Table 3, at all tested inlet particulate loadings, boiler loads, and JBR pressure drops the JBR exhibited excellent particulate removal efficiency, ranging from 97.7% to 99.3%.

Although the outlet particulate loading varied from 0.005 to 0.029 lb/MMBtu, analytical results indicate that from 20 to 80 percent of outlet particulate is sulfate (SO_4). Based on the calcium analyses performed on the same material, it is believed that the measured sulfate originated from gypsum carryover and acid mist carryover, so it is scrubber-generated. This finding reduces the estimate of actual ash mass loading at the outlet of the scrubber (actual fugitive emissions) to approximately 70% of the amount captured, measured and recorded during outlet testing.

Test I.D.	Approximate ESP Efficiency (%)	JBR ΔP (in. WC)	Boiler Load (MW)	JBR Inlet Mass Loading (lb/MMBtu)	JBR Outlet Mass Loading[1,2] (lb/MMBtu)	JBR Removal Efficiency (%)
AL2-1	90	18	100	1.288	0.029	***97.7***
AL2-2	90	10	100	1.392	0.010	***99.3***
AL2-3	90	18	50	0.325	0.005	***98.5***
AL2-4	90	10	50	0.303	0.006	***98.0***

[1] Federal U.S. NSPS is 0.03 lb/MMBtu for units for which construction began after 9/18/78
[2] Plant Yates Unit 1's permitted emission limit for existing units is 0.24lb/MMBtu (40% opacity)

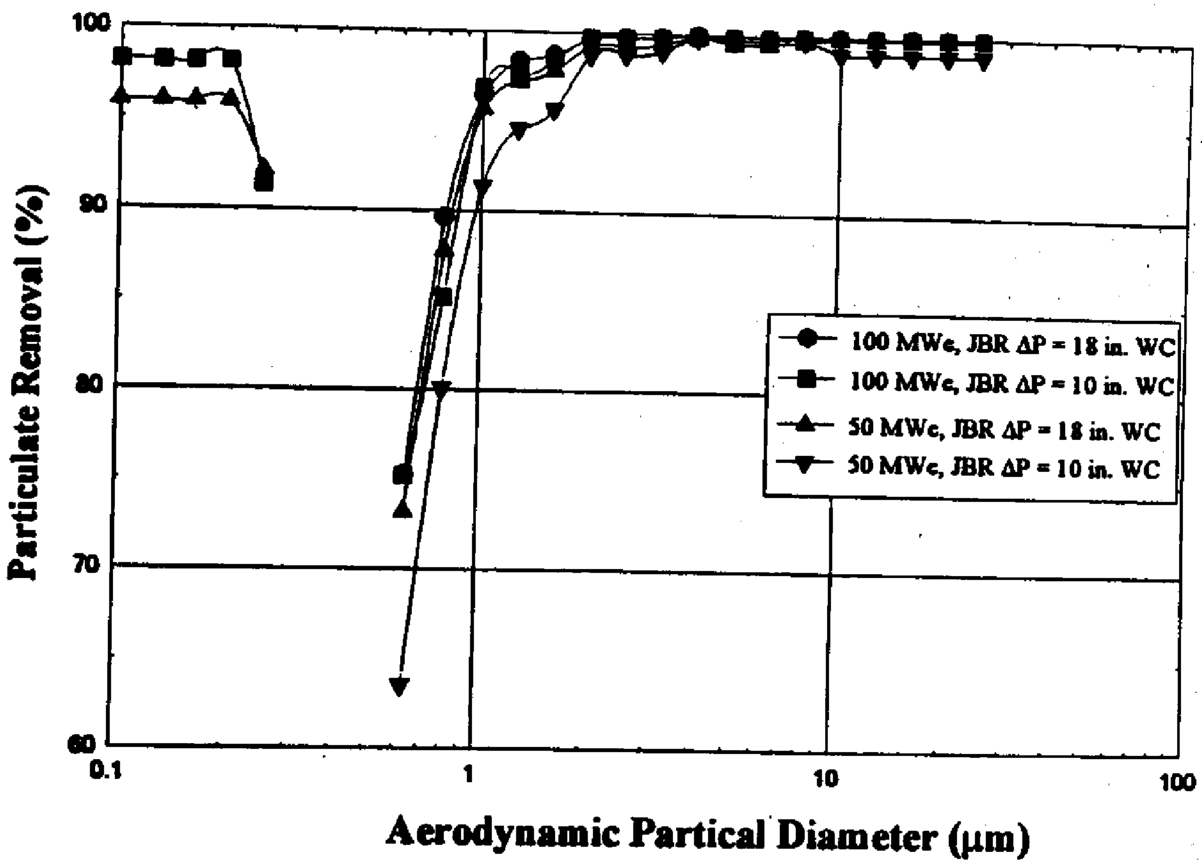
Table 3. Particulate Removal Testing - Summary of Results

<u>Particulate Removal Efficiency by Particle Size</u>

The particle size distribution of the scrubber inlet and outlet particulate matter was measured at all four test conditions as shown in Table 3. The results of these analyses indicate that excellent particulate removal efficiency occurred in most of the measured size ranges (cut-points). Figure 5 illustrates the particulate removal efficiency of the scrubber by comparing inlet and outlet mass loading at different particle size cut-points (shown using a logarithmic scale). The inlet data were combined for both 50 MW tests and for both 100 MW tests to simplify the plots since inlet conditions were identical in each case.

As observed in the plots, the 100 MW case showed better particulate removal efficiency than the 50 MW case at most cut-points. One possible explanation is based on the mechanism of particulate removal in the scrubber. Because the velocity of flue gas is higher at higher loads, the particulate has more momentum and is more likely to come into contact with the wet/dry interface as each flue gas "bubble" rises though the slurry.

As was reported during earlier particulate removal tests, and again observed in Figure 5, the best removal efficiencies were observed for particle sizes greater than 10μm. At all test conditions, there was greater than 99% particulate removal efficiency of particles in this size bin. In some cases, efficiency exceeded 99.99%. As the particle size decreased, there was a drop in observed particulate removal efficiency, but over 90% efficiency was observed at all particle sizes between 1μm and 10μm. Between 0.5μm and 1μm, the particulate removal dropped to sometimes negligible values. In this range, it is believed that acid mist carryover offset the ash particulate removal, resulting in poor particulate removal values. Analyses of the outlet catch indicated that an average of 30% of the outlet particulate can be attributed to gypsum and acid mist carryover. Below about 0.5μm, the particulate removal efficiency increased to above 90%. Also observed in Figure 7 was a higher particulate removal efficiency at the higher JBR ΔP values. This increase in removal efficiency ranged from 1 decade (90%), at the largest particle sized, to less than 1/10th of



Moderate-Ash Scrubber Particulate Removal Efficiency

FIGURE 5

a decade (10%) at the 0.5μm cut-point. The increased particulate removal at the higher JBR ΔP in this size range results from a deeper sparger tube submergence depth and therefore, a longer gas-phase residence time allowing more opportunity for the particulate to be captured in the slurry.

V. AIR TOXICS TESTING

The Yates CT-121 ICCT Project had two opportunities to measure its air toxics removal potential (also referred to as HAP or hazardous air pollutants). In 1993, Yates was chosen by the DOE as one of its eight coal-fired sites for an air toxics study[1] conducted on EPA's behalf in support of Clean Air Act Title II requirements for subsequent health risk determinations. In late 1994, the Yates ICCT Project expanded its scope of work to duplicate portions of that 1993 effort, in an attempt to validate the DOE's 1993 results. The results are both interesting and mutually supportive. However, the fossil fuel sources between the two tests were radically different and an exact comparison of results can not be easily made.

In 1993, the DOE was hoping to investigate three issues;

- Air toxics characterizations/penetrations in fossil fuel systems (fuel/boiler/ESP);
- Air toxics removal potential for postcombustion equipment (ESP/wet scrubber);
- Air toxics emissions factors in lb/10^{12} BTU.

From the 1993 results, the DOE concluded that:

- As much as 99% of the HAPs of interest are in the particulate phase;
- Specie removal across the ESP was proportional to total particulate removal;
- Uncertainty was high because most measurements were near the minimum analytical detection limits;
- Special difficulties were encountered with selenium, mercury and chromium (Cr^{6+}).

The 1994 air toxics sampling conducted as part of the ICCT Project by Radian at Plant Yates was performed to address the technical difficulties encountered during the 1993 tests; specifically:

- Selenium sampling and analysis;
- Mercury partitioning and speciation;
- Flyash penetration of the FGD process; and
- Source apportionment (origin of exiting and particulate matter),

as well as to be able to compare emissions and removals from a radically different coal source within the same boiler/ESP/scrubber flue gas pathway.

In comparing the results of the two efforts from a macro-perspective, several observations emerge that may effect the use of air toxics data in further rulemaking and health risk determinations:

- The 1993 effort saw significantly more measurement error than the 1994 effort;
- The Chiyoda CT-121 JBR is highly efficient at HAP removal;
- Sampling is very sensitive to ANY error (e.g.: Contamination) at these near-minimum detection level measurements; and
- Source apportionment identifies a significant emission contribution from particulate generated within the wet scrubbing process.

The uncertainty in the 1994 testing data is generally lower than that of the 1993 testing data (i.e., sampling procedures improved). Secondly, due to the larger uncertainty evident in some species in 1993, the accuracy of any calculated emission factors would likewise be suspect. It is apparent from the data that some species can be measured with much lower uncertainty than others. Fairly low uncertainty were found for arsenic, vanadium, and lead. Conversely, antimony, chromium, manganese, and nickel all had unacceptably large measurement confidence intervals, sometimes the confidence interval was 10 times larger than the measurement itself. Calculated removal efficiencies from the 1994 tests are shown in Figure 6. It is prudent to remind ourselves that extrapolation of admittedly uncertain data does not lend itself to producing certain results for emission factor estimation or subsequent health effects determinations. Caution should be emphasized in the use of these and any similar air toxics measurement data.

VI. GYPSUM QUALITY

The gypsum stacking area at Plant Yates had three separate cells for segregated impoundment; a “clean” gypsum stack area, a gypsum/ flyash stack area, and a recycle water pond. During Phase I (the low-ash test phase) of this demonstration project, the “clean” gypsum stack was used to dewater and store the pure-gypsum byproduct; decanted clear process water was collected in the common pond area and returned to the process. There was no blowdown, discharge or water treatment of scrubber process water. During the high-ash test phase (Phase II), the segregated gypsum/ash area was used for stacking the ash/gypsum mixture. Since these stacks are physically separated “cells”, the original “clean” gypsum stack then, sat idle during the later ash/gypsum phase of testing.

The gypsum slurry deposited in the both areas was originally with a high chloride content, due to the closed loop nature of the scrubber's operation, with liquid phase chloride concentrations calculated to be as high as 35,000 ppm at equilibrium. Because of these high chloride concentrations, any slurry-deposited gypsum solids would normally require washing in order to satisfy requirements of the gypsum wallboard or cement manufacturing industries. Core samples of the “clean” stack that were taken after the stack had been idle for over a year indicated a surprising result: the chloride concentration in the gypsum had decreased from about 6000 ppm, measured 3 months after Phase I completion, to less than 50 ppm less than one year later. Table 4 presents chloride data for the gypsum stack.

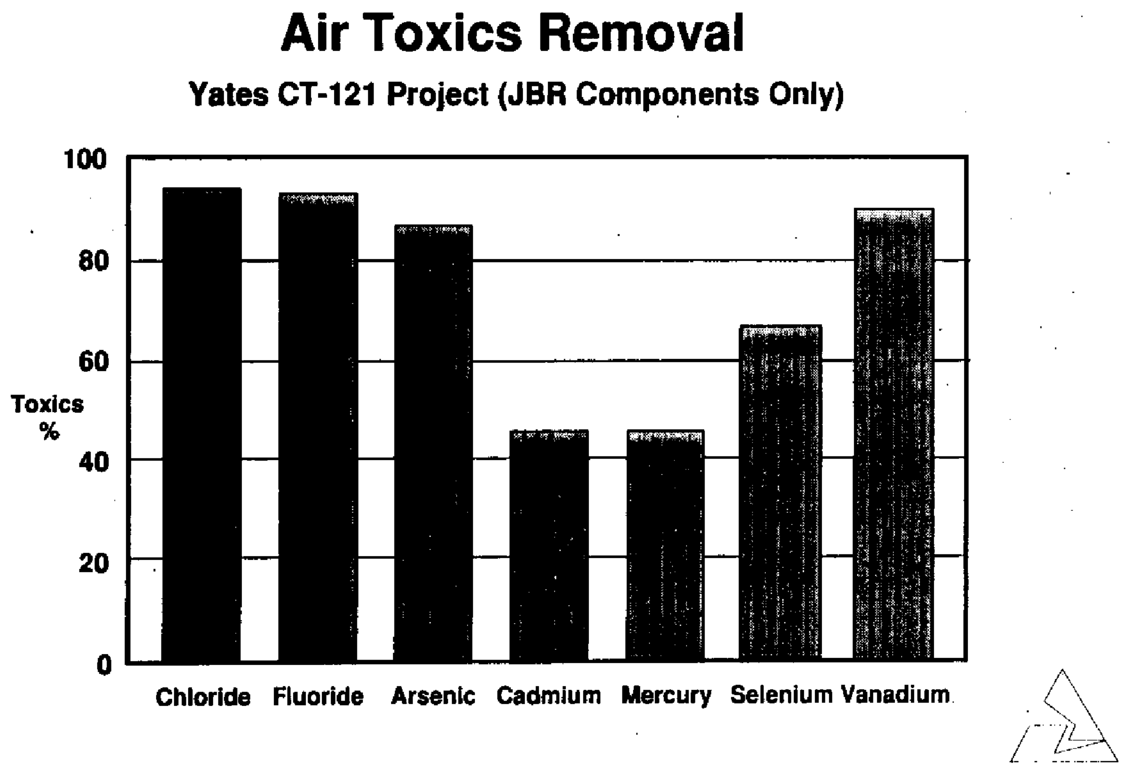

Air Toxics Removal
Yates CT-121 Project (JBR Components Only)
100
80
60
40
20
0
Toxics
%
Chloride
Fluoride
Arsenic
Cadmium
Mercury
Selenium
Vanadium
410123

FIGURE 6

There are two likely reasons for this decrease in chloride concentration in the gypsum in the "clean" gypsum stack. The first is that the rainfall that occurred over the idle year washed the gypsum and decreased the chloride concentration. The rate of chloride decrease over time, or as a function of rainfall, was not measured because this was an unplanned (and at the time, unknown) benefit of the gypsum stacking technique. The other reason lies in the fact that a majority of the chloride content in the gypsum solids is due to the chlorides in the water entrained in the gypsum solids. Core samples from the gypsum stack typically indicated that the solids content was approximately 83 wt.% on average shortly after the stack was idled. After one year, the solids content had increased to an average of 90 wt.% at a depth of 3 feet. Although this decrease in entrained water played some role in decreasing the chloride concentration in the gypsum, it is likely that rainwater washing of the stack was the predominant cause of the decrease in chloride concentration. This is further evidenced by the data presented in Table 4 that shows free moisture did not decrease at the 6 foot level, although chloride concentration did.

Of interesting note, was the 1996 issuance of a Plant Food Permit to Georgia Power that will allow the unrestricted sale of ash-free gypsum from the Yates Project to meet the unfilled demand for agricultural gypsum of 1 million+ ton/year in Georgia alone.

Dike	**Inactive Period**	**Sample Depth (ft)**	**Chloride (ppm)**	**Moisture (%)**
West	>90 days	4	***930***	16.0
	>90 days	8	***7610***	17.5
	>90 days	9.5	***5720***	17.7
	>90 days	14.5	***5540***	15.1
	>400 days	1	***60***	8.1
	>400 days	3	***40***	9.2
	>400 days	6	***20***	12.0
South	>90 days	10	***5740***	14.5
	>90 days	13.5	***5610***	17.4
	>90 days	16.5	***6710***	17.4
	>400 days	1	***20***	8.0
	>400 days	3	***20***	11.0
	>400 days	6	***20***	18.3

Table 4. Chloride and Moisture Levels in "Clean" Gypsum Stack decline over time

VII. SUMMARY

Chiyoda's CT-121 FGD process was very successfully tested at conditions far beyond design expectations. From an operating standpoint, the process was reliable, showed consistently high removals (SO_2, particulate, air toxics), was energy efficient and reagent efficient. From a chemical engineering standpoint, the mass transfer interactions are robust and resilient, only limited at conditions far beyond design parameters. This would allow a designer / operator to install a cost effective CT-121 system that would give consistently excellent service, even in periods of difficult operating conditions.

1. "A Study of Toxic Emissions from a Coal-Fired Power Plant Utilizing an ESP While Demonstrating the ICCT CT-121 FGD Project," Radian Corporation, Final Report for U.S. DOE, Contract No., DE-AC22-93PC93253. June 16, 1994.

Revised: November 18, 1996

THE HEALY CLEAN COAL PROJECT
AN OVERVIEW

John B. Olson, P.E. (jolson@aidea.alaska.net; 907.269.3000)
Deputy Director (Development)
Dennis V. McCrohan, P.E. (dmcrohan@aidea.alaska.net; 907.269-3000)
Deputy Director (Energy)
Alaska Industrial Development and Export Authority
480 West Tudor Road
Anchorage, AK 99503

ABSTRACT

The Healy Clean Coal Project, selected by the U.S. Department of Energy under Round III of the Clean Coal Technology Program is currently in construction. The project is owned and financed by the Alaska Industrial Development and Export Authority (AIDEA), and is cofunded by the U.S. Department of Energy. Construction is scheduled to be completed in August of 1997, with startup activity concluding in December of 1997. Demonstration, testing and reporting of the results will take place in 1998, followed by commercial operation of the facility. The emission levels of NOx, SO_2 and particulates from this 50 megawatt plant are expected to be significantly lower than current standards. The project status, its participants, a description of the technology to be demonstrated, and the operational and performance goals of this project are presented herein.

BACKGROUND

In September 1988, Congress provided $575 million to conduct cost-shared Clean Coal Technology (CCT) projects to demonstrate technologies that are capable of retrofitting or repowering existing facilities. To that end, a Program Opportunity Notice (PON) was issued by the Department of Energy (DOE) in May 1989, soliciting proposals to demonstrate innovative energy efficient technologies that were capable of being commercialized in the 1990's, and were capable of (1) achieving significant reductions in the emissions of sulfur dioxide and/or the oxides of nitrogen from existing facilities to minimize environmental impacts such as transboundary and interstate pollution and/or (2) providing for future energy needs in an environmentally acceptable manner.

In response to the PON, DOE received 48 proposals in August 1989. After evaluation, 13 projects were selected in December 1989 as best furthering the goals and objectives of the PON. The projects were located in ten states and represented a variety of technologies.

One of the 13 projects selected for funding is the Healy Clean Coal Project proposed by the Alaska Industrial Development and Export Authority (AIDEA). The project will demonstrate the combined removal of SO_2, NO_X, and particulates from a new 50 megawatt electric coal-fired power plant using both innovative combustion and flue gas cleanup technologies. AIDEA will own the Project, perform as DOE grant recipient, administer state funds, obtain financing through sale of bonds, and manage the Project. The architect/engineer for the project is Stone & Webster Engineering Corporation. Fairbanks utility Golden Valley Electric Association (GVEA) will operate the facility and pay for power generated under terms of a power sales agreement.

TECHNOLOGY TO BE DEMONSTRATED

Coal provided by the Usibelli Coal Mine, adjacent to the project site, will be pulverized and burned at the new facility to generate high-pressure steam. The high-pressure steam will be supplied to a steam turbine generator to produce electricity. Emissions of SO_2 and NO_x from the plant will be controlled using TRW's Entrained Combustor with limestone injection in conjunction with a boiler designed by Foster Wheeler. Further SO_2 and particulate removal will be accomplished using the Activated Recycle Spray Dryer Absorber System and Bag Filter developed by Joy Environmental Equipment, Inc.

The TRW Entrained Combustor is designed to operate under fuel-rich conditions, utilizing two staged combustion to minimize NO_x formation. These conditions are obtained using a precombustor for heating the fuel-rich main combustor for partial combustion with combustion completion occurring in the boiler. The first and second stages of combustion produce a temperature high enough to generate a slag (liquid ash) while reducing the fuel-bond nitrogen to molecular nitrogen (N_2). The third and final stage of combustion in the boiler occurs at a combustion temperature maintained below the temperature that will cause thermal NO_x formation.

The combustor is also used to reduce SO_2 emissions by the injection of pulverized limestone into the hot gases as they leave the combustor and enter the furnace. This technique changes the limestone into lime (flash calcination), which reacts with the sulfur compounds in the exhaust gas to form calcium sulfate. SO_2 is removed with combustor and boiler bottom ash. The flue gas, which contains the remaining sulfur compounds, calcium sulfate, and other solid particles leaves the boiler and passes through a spray dryer absorber and a bag filter for further SO_2 and particulate removal prior to exiting through the stack.

The innovative concept to be demonstrated in SO_2 removal is the reuse of the unreacted lime, which contains minimal fly ash, in the second-stage spray dryer SO_2 removal. The majority of fuel ash is removed in the combustor in the form of slag. A portion of the ash collected from the spray dry absorber vessel and the bag filter are first slurried with water, chemically and physically activated, and then atomized in the spray dryer absorber vessel for second-stage SO_2 removal. Third stage SO_2 and particulate removal occurs in the bag filter as the flue gas passes through the reactive filter cake in the bags.

The use of limestone in the combustor, combined with the recycle system, replaces the more expensive lime required by commercial spray dryer absorbers, reduces plant wastes, and increases SO_2 removal efficiency when burning high- and low-sulfur coals.

The integrated process is expected to achieve SO_2 removal greater than 90%, a reduction in NOx emissions to 0.2 pounds per million Btu. The integrated process is suited for new facilities or for repowering or retrofitting existing facilities. It provides an alternative technology to conventional pulverized coal-fired boiler flue gas desulfurization (FGD) and NO_x reduction processes, while lowering overall operating costs and reducing the quantity of solid wastes.

The demonstration project is under construction adjacent to the Golden Valley Electric Association (GVEA) existing Healy No. 1 pulverized coal-fired power plant near Healy, Alaska. Subbituminous coals from the adjacent Usibelli Coal Mine (UCM) will be the fuels. The primary fuel to be fired is a blend of run-of-mine (ROM) and waste coals. ROM coal is a subbituminous coal with a higher heating value (HHV) range of 7500-8200 Btu/lb, a low average sulfur content of 0.2 percent, and an average ash content of 8 percent. The waste coal is either a lower grade seam coal or ROM contaminated with overburden material having an HHV range, average sulfur content, and average ash content of approximately 5,000-9,000 Btu/lb, 0.15 percent, and 20 percent respectively. The project will demonstrate the ability of slagging combustors to utilize low quality coals effectively. It is anticipated that coal consumption will average 330,000 tons annually over the 40 year plant life.

PROJECT STATUS

The projected project cost is about $267 million with $117.3 being a grant from the U.S. Department of Energy, and the remainder a combination of state grant, interest earnings, contributions from project participants, AIDEA bonds, and power sales. Construction of the HCCP began in the Spring of 1995 and is scheduled for completion in late 1997. The construction is on schedule, with startup activities planned for the fall of 1997. Demonstration testing and reporting of the results, scheduled to commence upon completion of construction, will take place in 1998. Following completion of the demonstration test program, the plant will be operated and maintained as a commercial electric generation plant.

Coal Reburning for Cost-Effective NO_x Compliance

B. A. Folsom, T. M. Sommer, D. A. Engelhardt, and D. K. Moyeda
Energy and Environmental Research Corporation

R. G. Rock
Eastman Kodak Company

D. T. O'Dea
New York State Electric and Gas

Scott Hunsicker
Fuller Power Corporation

J. U. Watts
U.S. Department of Energy
Pittsburgh Energy Technology Center

Fifth Annual Clean Coal Technology Conference
Tampa, Florida
January 7-10, 1997

ABSTRACT

This paper presents the application of micronized coal reburning to a cyclone-fired boiler in order to meet RACT emissions requirements in New York State. Discussed in the paper are reburning technology, the use of a coal micronizer, and the application of the technology to an Eastman Kodak unit. The program is designed to demonstrate the economical reduction of NO_x emissions without adverse impact to the boiler.

I. INTRODUCTION

The Eastman Kodak Company's Kodak Park Site is one of the largest industrial parks in the nation, spanning an area in excess of 1300 acres. There are over two hundred buildings on the site that produce thousands of different photographic and chemical products. Supporting production are two power plants containing a total of fourteen boilers. Kodak has an agreement with the New York State Department of Environmental Conservation (NYSDEC) in which it states that Kodak will install coal or natural gas reburning systems on all four of its cyclone boilers. Kodak has recently completed installation of a natural gas reburning system on #43 Boiler which is located on the western side of the Kodak Park Site facility. The upgrades of the three remaining boilers (#15, #41, and #42) are planned for the 1996 thru 1998 time frame. #15

Boiler is located apart from the other three cyclone boilers, on the eastern section of the facility, approximately three miles from #43 Boiler. The original schedule for upgrades was #43 by 1996, #41 and #42 by 1997, and #15 by 1998.

In September 1996, New York State Electric and Gas (NYSEG) presented Kodak with an alternative: NYSEG and Kodak could work together with the United States Department of Energy (DOE) to complete the upgrade of #15 Boiler if Kodak would use micronized coal as the reburn fuel instead of natural gas. This proposal was attractive to Kodak for three reasons: (1) there is no natural gas main pipeline in eastern Kodak Park Site; (2) natural gas is currently more than twice the cost of coal; and (3) DOE would co-fund the cost of installing the new system. The project will enable Kodak to meet the terms and conditions of the Kodak/DEC agreement in a more economical and timely fashion.

Eastman Kodak #15 Boiler

Kodak's #15 Boiler, installed in 1956, is a cyclone-fired unit located at Kodak Park in Rochester, New York (see Figure 1). Supplied by Babcock & Wilcox Co., the unit contains two cyclone furnaces on the front wall firing crushed Eastern Bituminous coal. It typically operates at steam generation rates between 300,000 to 400,000 lb/hr; peak generation rate is 440,000 lb/hr. The cyclone furnaces operate at a very high heat release rate, creating molten slag which is captured on the cyclone walls and flows to a slag tap at the bottom of the furnace. Particulate control is maintained by an electrostatic precipitator.

In February 1996, EER performed a baseline test and measured NO_x emissions at 1.21 lb/10^6 Btu for full load and 0.92 lb/10^6 Btu for low load. Baseline CO emissions were 56 ppm and 34 ppm at full and low loads respectively. The results correlated closely with Kodak's belief that the baseline NO_x emissions are 1.25 lb/10^6 Btu and baseline CO is less than 100 ppm.

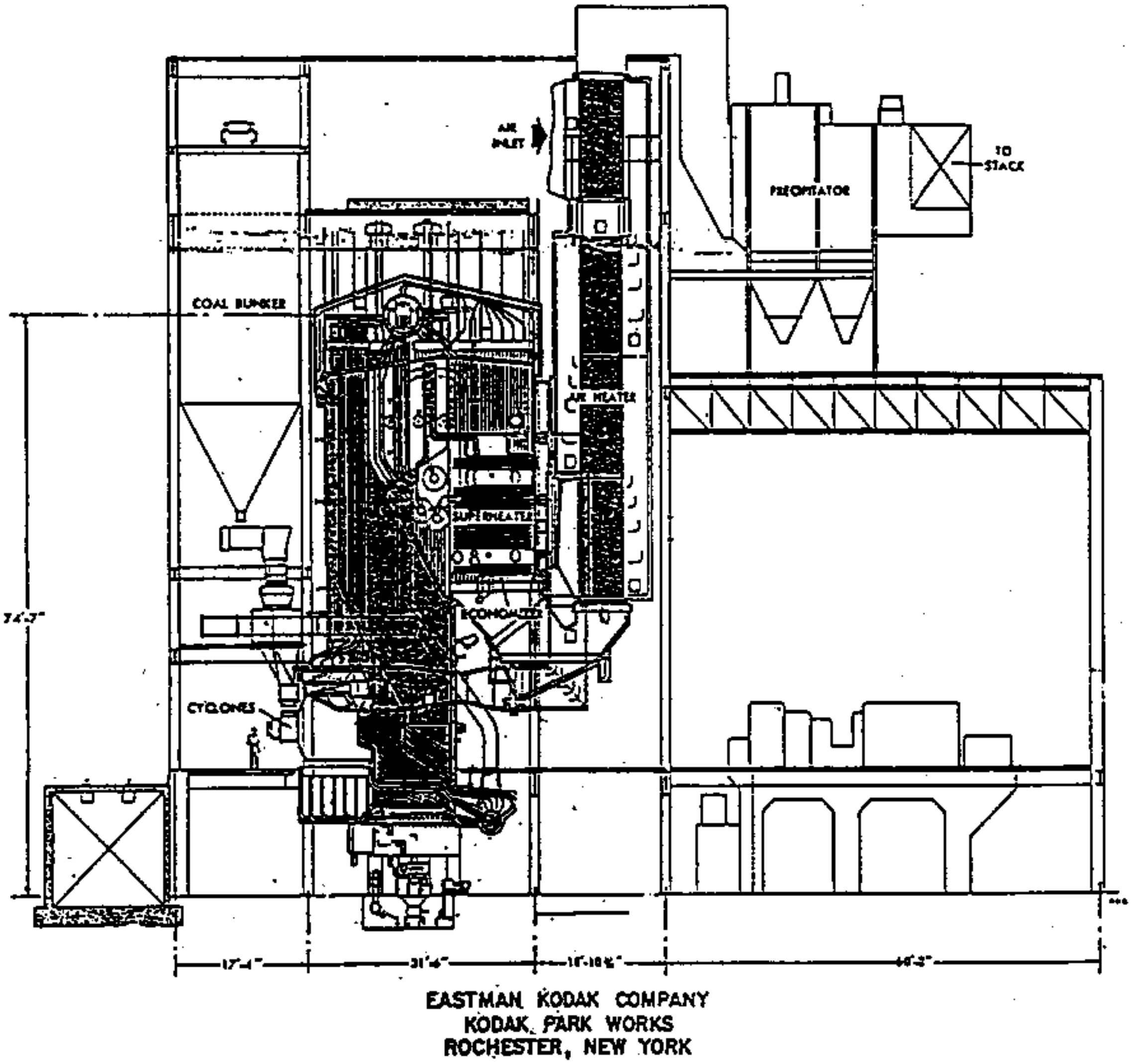


Figure 1. Kodak #15 Boiler.

<u>Coal Reburning Technology for NO_X Control</u>

Coal Reburning is a NO_X control technology whereby NO_X is reduced by reaction with hydrocarbon fuel fragments [1]. A typical application of coal reburning to a coal-fired boiler is illustrated in Figure 2. No physical changes to the main burners (cyclone furnaces in this case) are required. The burners are simply turned down and operated with the lowest excess air commensurate with acceptable lower furnace performance considering such factors as flame stability, carbon loss, and ash deposition.

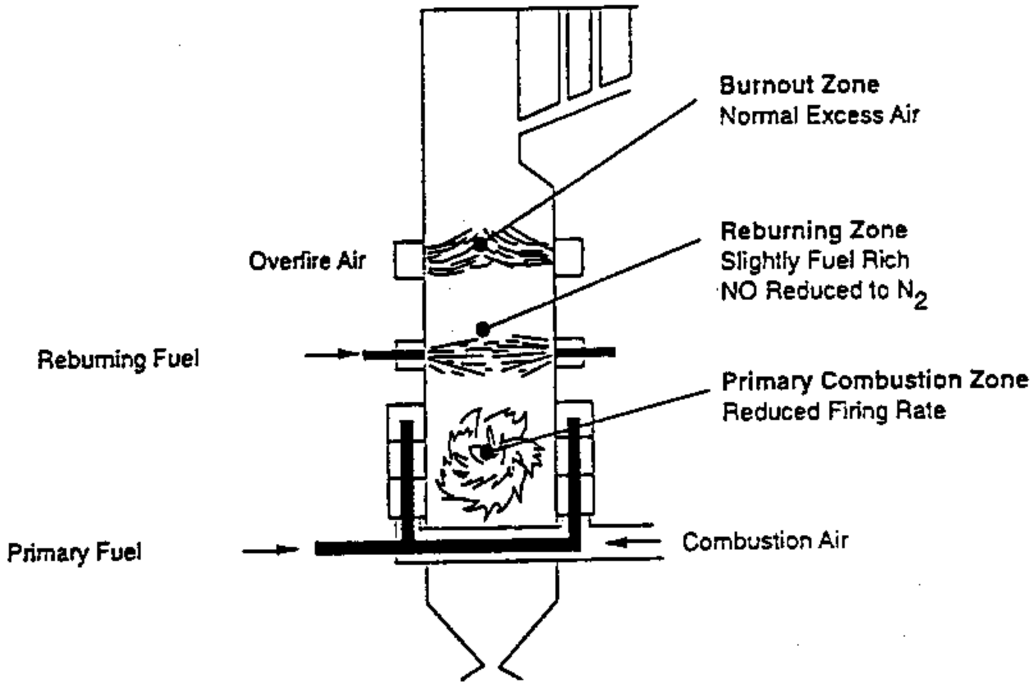


Figure 2. Application of reburning technology to a utility boiler.

The technology involves reducing the levels of coal and combustion air in the burner area and injecting reburn fuel (micronized coal) above the burners followed by the injection of overfire air (OFA) above the reburn zone. This three-zone process creates a reducing area in the boiler furnace within which NO_x created in the primary zone is reduced to elemental nitrogen and other less harmful nitrogen species. Each zone has a unique stoichiometric ratio (ratio of total air in the zone to that theoretically required for complete combustion) as determined by the flows of coal, burner air, reburn fuel, and OFA. The descriptions of the zones are as follows:

> *Primary (burner) Zone:* Coal is fired at a rate corresponding to 75 to 90 percent of the total heat input. NO_x created in this zone is slightly lower than normal operation due to the lower heat release and the reduced excess air level.

> *Reburn Zone:* Reburn fuel (micronized coal) is injected above the main burners through wall ports. The reburn fuel consumes the available oxygen and produces hydrocarbon fragments (CH, CH_2, etc.) which react with NO_X from the lower furnace, reducing it to elemental nitrogen, N_2. Optimum NO_X reduction performance is typically achieved when the reburn zone is operated at about 90% of stoichiometric, which is slightly fuel rich (reducing) [2]. NO_X reduction can be adjusted by varying the reburn fuel injection rate, typically over the range of 10-25% of total boiler heat input. To minimize the reburn fuel required to achieve fuel rich conditions in the reburn zone, EER's design utilizes injectors rather than burners, which would have introduced additional air [3].

Burnout (exit) Zone: The oxygen required to burn out the combustibles from the reburn zone is provided by injecting air through overfire air ports positioned above the reburn zone. These ports are similar to conventional overfire air ports except that they are positioned higher in the furnace so as to maximize the residence time for NO_X reduction occurring in the reburn zone. OFA is typically 20 percent of the total air flow. OFA flow rate and injection parameters are optimized to minimize CO emissions and unburned carbon-in-fly ash.

The concept of NO_X reduction via reactions with hydrocarbon fuels has been recognized for some time [4]. The work has progressed from analysis and pilot-scale tests [2] through several full-scale demonstrations including three installations on coal-fired utility boilers as part of the U.S. Department of Energy's Clean Coal Technology Program [5] and a commercial installation at New York State Electric and Gas' Greenidge Plant [6].

Goals of Micronized Coal Reburning Demonstration

The objective of the coal reburning demonstration is to evaluate the applicability of the technology to full-scale cyclone-fired boilers for reduction of NO_x emissions. The project goals are:

Reduce NO_x emissions at full load from the current established baseline of 1.25 lb/10^6 Btu to 0.60 lb/10^6 Btu.

Maintain CO emissions at or below 100 ppm.

Minimize the impact on boiler efficiency.

Reduce NO_x without serious impact to cyclone operation, boiler performance or other emissions streams.

Demonstrate a technically and economically feasible retrofit technology.

Demonstrate the advantages of micronized coal reburning over conventional coal reburning.

Several derived benefits can be realized with coal reburning. From an economic standpoint, coal reburning is less expensive to install and costs less to operate than selective catalytic reduction. With micronized coal as the reburn fuel, the utilization of the fuel is enhanced which results in reduced carbon-in-ash when compared to conventional coal reburning, which also reduces particulate loading to the ESP. These benefits outweigh the additional power requirements associated with operation of the micronizers.

II. PROCESS DESIGN

The application of reburning to a particular boiler requires careful consideration of the furnace flow field characteristics and the boiler design when developing reburning system specifications. To optimize the emissions control performance and to minimize any negative impacts of the retrofit, it is necessary to develop a design that achieves rapid and uniform mixing of the reburn fuel and overfire air streams, but minimizes the extent of modifications to the boiler heat release and heat absorption profiles.

Controlling Process Parameters

Since the early 1980's, EER has extensively evaluated the reburning process at bench, pilot and full-scale to identify the parameters that control process performance. The results of these studies have shown that the most critical parameters are: primary NO_x level; reburn zone temperature and residence time; reburn zone stoichiometric ratio; and mixing of the reburn fuel and overfire air with the bulk furnace gases.

Reburn Zone Stoichiometric Ratio: The impact of this parameter on the NO_x emissions achievable with various reburn fuels is shown in Figure 3 [7]. as shown in the figure, overall NO_x reductions are highest when the ratio is approximately 0.9. To minimize the amount of reburn fuel needed to reach the optimum ratio, the primary combustion zone is operated as close to stoichiometric as possible. It should be noted, however, that with cyclone-fired boilers reducing the stoichiometric ratio in the primary zone will disrupt the slagging characteristics of the cyclone. Therefore, the fuel-to-air ratio in this area remains relatively unchanged.

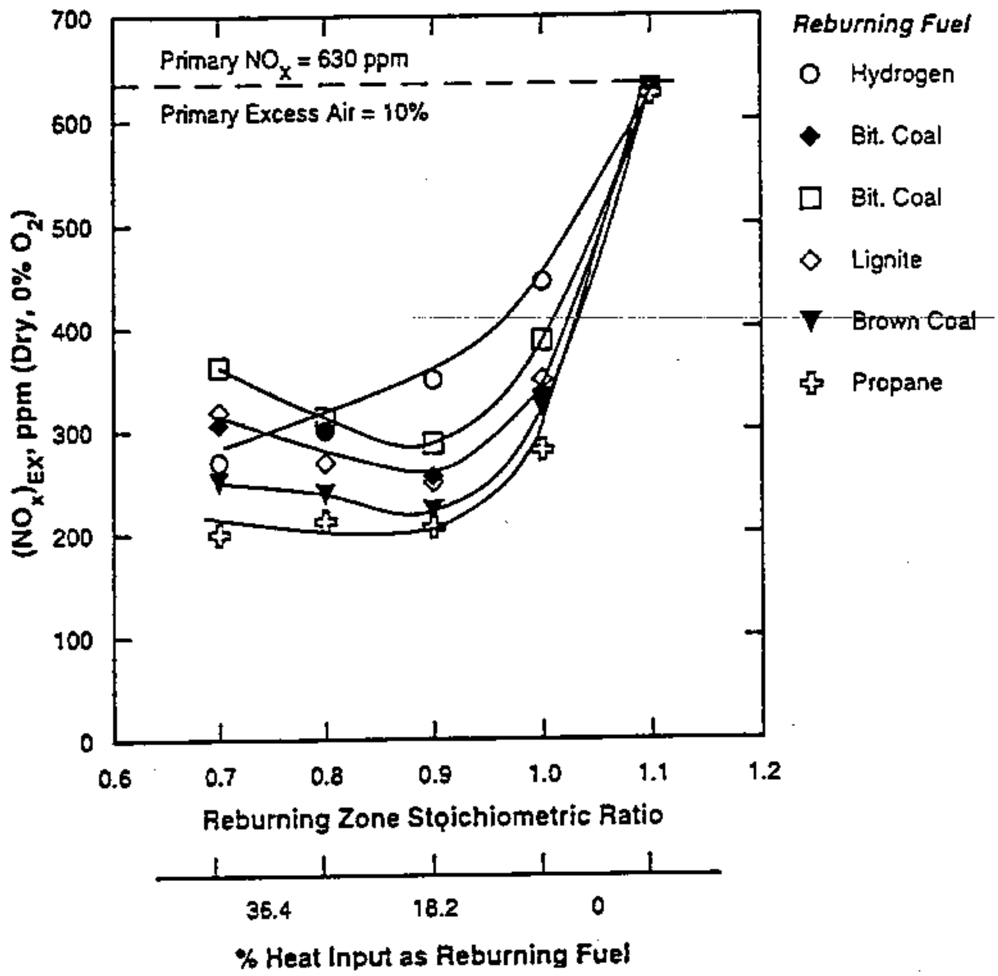


Figure 3. Impact of reburning zone stoichiometric ratio and reburning fuel type on reburning performance.

Furnace Temperatures and Residence Times: As defined above, the reburn zone is that area of the boiler situated between the reburn fuel injectors and overfire air injectors. The amount of time required for the flue gas to pass thru this area is referred to as the residence time. The locations of injectors are selected using the following criteria:

> High temperatures in the reburn zone are preferred in order to maximize the rate of NO_x reduction. This suggests that the reburn fuel be injected just downstream of the primary zone.
>
> The temperature in the burnout zone must be high enough to allow oxidation of carbon monoxide and hydrocarbon fragments from the reburn zone to occur readily.
>
> The residence time must be of sufficient duration for the reactions to occur. EER has

evaluated a number of reburning systems and concluded that a residence time of 0.2 to 0.5 seconds will achieve high efficiency NO_x reduction.

Mixing: Pilot-scale studies of the reburning process have shown the importance of effective mixing in both the reburn and burnout zones [8]. Effective mixing of the reburn fuel optimizes the process efficiency by making the most efficient use of the available furnace residence time. Effective mixing of the overfire air reduces carbon monoxide emissions and unburned carbon or soot.

Design Approach

The final design was established on the basis of small-scale flow modeling, thermal heat transfer computer analysis, and operation of a pilot-scale micronizer using EER's Boiler Simulator Furnace. The reburn fuel and overfire air injection elevations were selected to provide the maximum amount of residence time possible in the reburn zone in order to maximize the NO_x control performance. This approach involved injection of the reburn fuel at an elevation in the furnace just above the exit of the cyclones and injection of overfire air at a distance downstream of the coal injectors that would provide for a maximum bulk residence time (Figure 4).

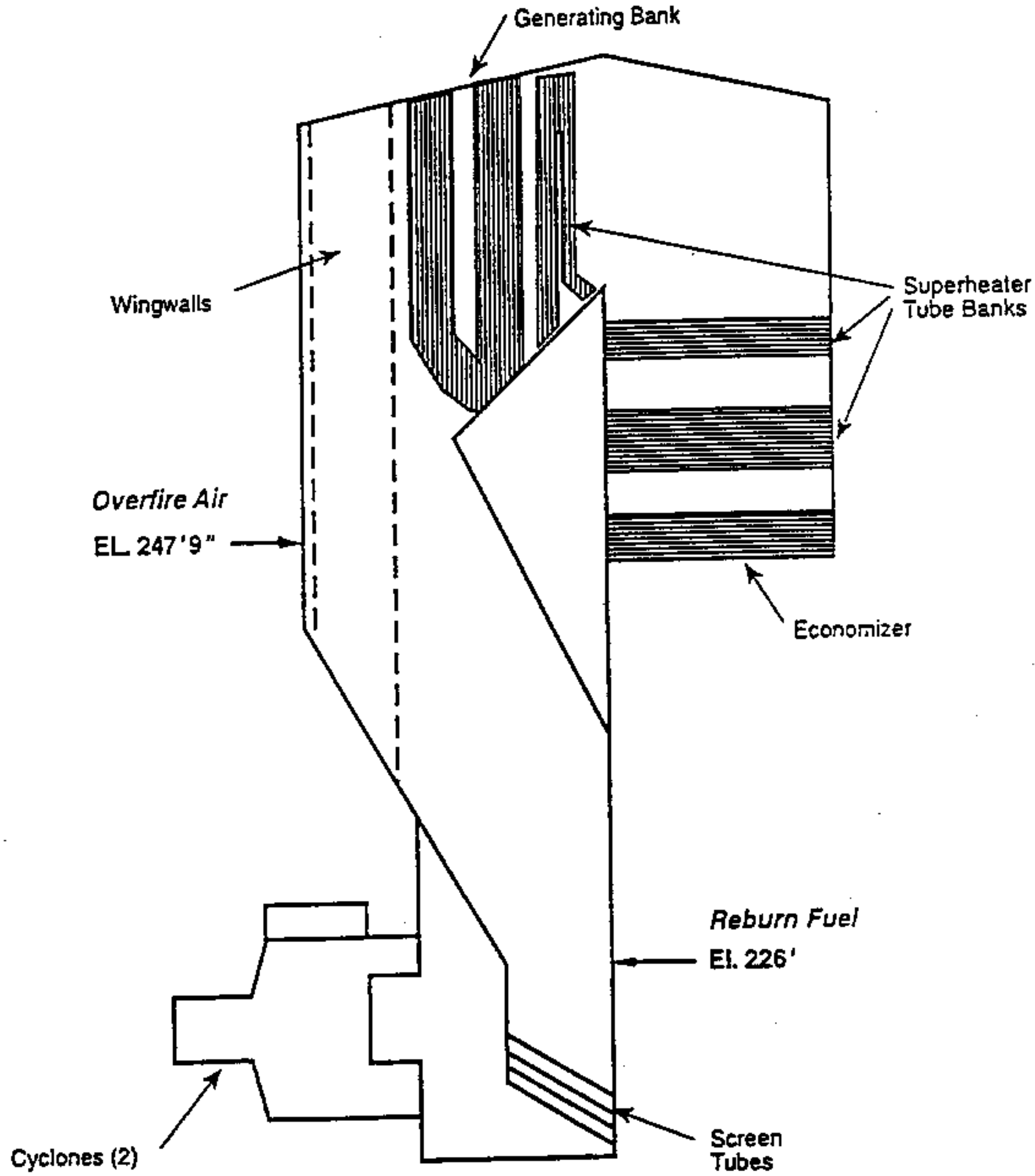


Figure 4. Reburn fuel and overfire air injection elevations for Kodak #15 Boiler.

The reburn fuel is pneumatically transported to the boiler using recycled flue gas (FGR) as the carrier medium. The fuel is then introduced into the boiler thru injectors that are designed to rapidly mix the small quantity reburn fuel with the furnace gases. FGR is particularly suited as a carrier gas in lieu of air since it consists of a very low level of O_2. Note that any O_2 introduced as carrier gas must be consumed by additional reburn fuel. The use of FGR minimizes this fuel requirement.

III. SYSTEM DESCRIPTION

Coal Micronizer

Preparation of the reburning fuel is performed using a MicroMill system supplied by Fuller Mineral Process Inc. The MicroMill is a patented centrifugal-pneumatic mill that works on the principle of particle-to-particle attrition. Coal is conveyed with a hot air stream into the cone area, creating a vortex of air and coal particles. As the diameter of the cone section of the mill becomes larger, the air to coal velocity decreases. The coal assumes a position in the cone based on each particle's size and weight. Particles of similar size will form bands of material with the larger particles at the bottom of the cone. Smaller particles will move through these bands and enter the vortex created by the rotating blades in the rotational impact zone of the mill. As these smaller particles collide with the larger particles, size reduction occurs. When a particle's size is small enough to attain the required velocity, it passes through the blades located in the scroll section of the mill and exits the mill to a static classifier.

A static classifier is used for final particle size distribution. Oversized material falls through a rotary air lock and back into the feed airstream of the mill. Stripping air provided to the classifier can be adjusted to fine tune the classifier collection efficiency allowing larger or smaller particles to pass to the boiler.

The MicroMill system can fit in approximately a thirteen foot by nine foot area and is only about twelve feet high. The mill's overall size and weight made it an ideal choice for Kodak=s tight space limitations and its modular construction makes it easy to perform maintenance. The mill is designed with wear resistant materials in areas contacting the feed being processed to minimize maintenance. When maintenance is required, the cone can be unbolted, lowered on the pivot pin and rotated for access to the rotor, wear liners and replaceable blades.

The MicroMill is supported by Fuller=s extensive research and development facilities which includes a full scale MF3018 MicroMill for product testing and demonstration. The Kodak feed materials were tested on this unit to determine expected capacity, fineness and power consumption. In the lab a capacity of three tons per hour at 86% passing 44F was obtained. The limiting factor in the laboratory was motor HP. The motor for the project was increased from 150 horsepower to 200 horsepower; thus higher capacities are expected in the field. Power consumption expected for the mill is about 37.3 KW/ton of material processed. In addition, the fineness required for the application is 80% passing 44F, which will further increase the capacity of the system. Flexibility has been designed into the system to provide a higher fineness product or greater capacity at a lower fineness.

The two-mill system for the Kodak project includes:

Mill and motor
Classifier

Recycle and feed rotary airlock
Blow through tee and feed piping
Classifier and mill air control valves.
Air flow meter

The mill is equipped with a water-cooled bearing jacket, vibration sensor, bearing RTD=s and a proximity switch. The bearing jacket will allow the use of Kodak=s uncooled flue gas as a transport medium. By utilizing the water cooled jacket the need for expensive flue gas cooling equipment was eliminated.

Coal Transportation and Injection

The coal transportation system is shown in Figure 5. The slipstream for flue gas is extracted from the boiler just downstream of the precipitator and is boosted by a single fan to feed both coal micronizers. FGR is used to transport coal to the boiler and also boost its injection momentum to ensure that the reburn fuel is mixed effectively in the furnace.

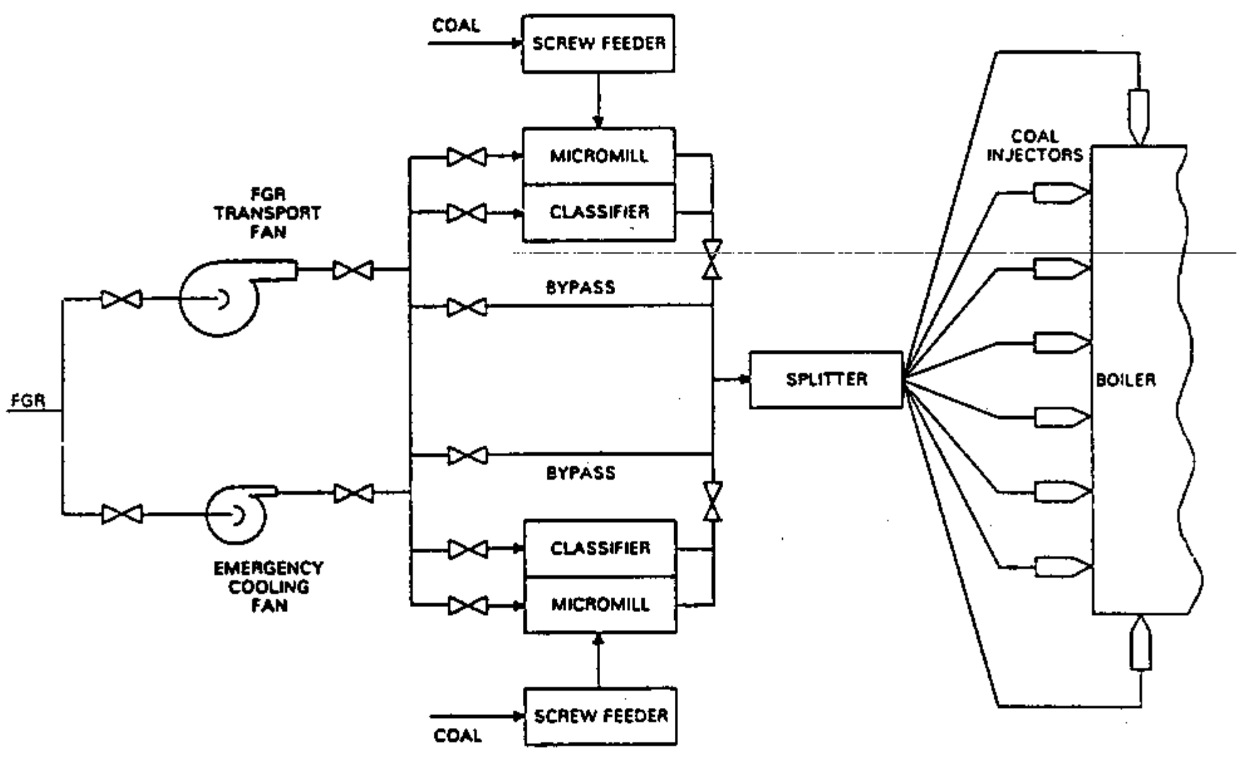


Figure 5. Micronized Coal Feed System

Two coal micronizers with classifiers are used in the system. Each micronizer is supplied coal from a bunker thru a screw feeder. The FGR system assists in the micronizing process and in operation of the classifiers. The mills are capable of operating singly or as a pair, although, due to capacity limitations, both may be required to produce the targeted NO_x reduction.

The micronized coal exiting the two mills is merged into a single 18-inch pipe for transportation to the boiler. The line is then divided into eight 6-inch segments by a coal flow splitter supplied by EER.

The splitter is designed to apportion the coal into equal segments without incurring any pressure drop. Upstream of the splitter is a coal rope breaker (RopeMaster[7]) supplied by Rolls-Royce/International Combustion, which will enhance the splitter's effectiveness. Downstream of the splitter are eight FlowMastEER[7] dampers designed by EER that are used to perform final adjustments to the coal flow balance. The dampers can also be used to create flow biasing.

Eight micronized coal injectors are installed, six on the rear wall and one on each side wall near the rear wall. The injectors utilize the considerable momentum provided by the FGR transport gas plus additional design features to enhance coal penetration. Each injector is equipped with a variable swirl device to control the mixing characteristics of each fuel jet as it enters the furnace. Adjustments will be made during initial startup to optimize the injector effectiveness. The coal injectors were designed by EER specifically for this project.

Overfire Air System

Located on the front wall are four overfire air injectors. These injectors utilize EER's Second Generation dual-concentric overfire air design. This is EER's second application of this concept [9]. The injectors are designed to provide good jet penetration as well as good lateral dispersion across the boiler depth and width. Each injector is equipped with an integral damper to maintain the desired injection velocity as load changes and a swirler which, when adjusted, provides for optimum mixing in the burnout zone.

Controls

Kodak installed a new Coen burner management system and replaced the complete boiler control system with a Westinghouse WDPF distributed digital control system. The new controls operate both the existing equipment and the micronized coal reburning system, with all normal start/stop/modulate operator actions occurring in the control room. Critical operations are interlocked to prevent inadvertent operation of equipment when such operation may present an operating hazard or other undesirable condition. The controls are designed to shut down the reburning system while maintaining operation of the boiler. Kodak's insurance carrier, Factory Mutual, has approved this control arrangement. Previous to this project, EER reburning retrofits were approved by Factory Mutual and Hartford Steam.

Operation

During operation of the reburning system, the total fuel to the boiler is the sum of the fuel to the cyclones plus the fuel to the reburn injectors. Any change in the amount of reburn fuel must balanced by an converse change in the fuel to the cyclones. During normal operation, the boiler generates steam at rates between 300,000 and 400,000 lb/hr. The lower limit of 300,000 lb/hr is based on the amount of bottom ash required to prevent slag freezing. The range of reburn fuel injection is based on the following two factors:

> The minimum reburn fuel injection rate is based in lower operational limit of the coal preparation equipment (coal feeder, micronizer, classifier, etc.).
>
> The maximum reburn fuel injection rate is that amount required raise the boiler from the cyclone minimum operating level (300,000 lb/hr steam) to the boiler maximum operating level (400,000 lb/hr steam). Note that the minimum cyclone operating level may be lower than 300,000 lb/hr during reburning since reburn fuel ash also contributes to the bottom ash total. The maximum amount of reburn fuel that can be injected is estimated to be 25% of the total heat input.

At boiler full load with maximum operation of reburning, load can be reduced by lowering the injection rate of the reburn fuel. The load on the cyclones would remain the same. This capability is described in Figure 6.

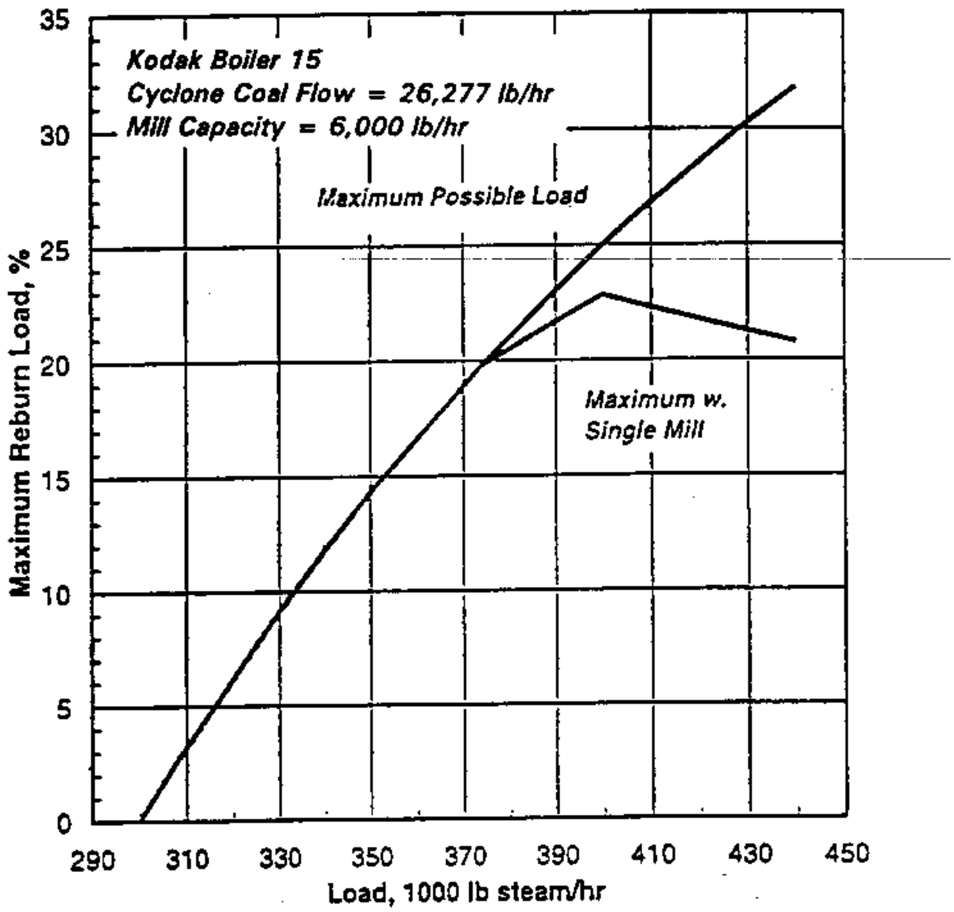


Figure 6. Maximum level of reburning system operation achievable while maintaining minimum coal flow to cyclones.

IV. SUMMARY

The coal reburning installation at Eastman Kodak Company will permit Kodak to meet RACT emissions requirements in New York State. The project, conducted under the auspices of the U.S. Department of Energy's Clean Coal Technology Program, is designed to demonstrate the economic advantages of using coal micronizer technology versus conventional coal reburning. Testing of the system will verify the target goals of NO_x emissions reduction and determine the full range of operation, including turndown capabilities. The testing will also be used to develop a database of technical information that can be applied to similar boilers.

Coal reburning is less expensive to install and costs less to operate than selective catalytic reduction (SNCR). Using coal as the reburn fuel results in economical reburn fuel selection, decreased primary mill capacity, no additional chemical/catalyst cost, and no ammonia slip normally associated with SNCR. With micronizer technology feature, the utilization of the reburn fuel is enhanced which results in reduced carbon-in-ash when compared to conventional coal reburning, which also reduces particulate loading to the ESP.

This paper has focused on reburning technology, a description of the project and its inherent benefits including. Future papers will present the results of extensive testing.

V. ACKNOWLEDGMENTS

The following organization is acknowledged for their contributions to the project: New York State Energy Research and Development Authority and the U.S. Department of Energy's Clean Coal Technology Program. EER would also like to acknowledge the support of Rolls-Royce/International Combustion and Parsons Power Group Inc.

VI. REFERENCES

1. J. O. L. Wendt et. al., Reduction of Sulfur Trioxide and Nitrogen Oxides by Secondary Fuel Injection, Fourteenth Symposium (International) on Combustion, pp. 897-904, (1973).

2. S. B. Greene et. al., Bench Scale Process Evaluation of Reburning and Sorbent Injection for In-Furnace NO_x Reduction, Paper No. 84-JPGC-APC-9, presented at the ASME Joint Power Generation Conference (1984).

3. W. R. Seeker, et. al., Controlling Pollutant Emission from Coal and Oil Combustor Through the Supplemental Use of Natural Gas, Final Rpt., GRI 5083-251-0905, 1985.

4. U.K. Patent Office. *Process for Disposal of Oxides of Nitrogen.* Robert D. Reed, John Zink Company. U.K. Patent No. 1,274.637, 1970.

5. B. A. Folsom, et. al., Three Gas Reburning Field Evaluations: Final Results and Long Term Performance, presented at the EPRI/EPA 1995 Joint Symposium on Stationary Combustion NO_X Control, Kansas City, Missouri (May 16-19, 1995).

6. B. A. Folsom, et. al., Advanced Gas Reburning Demonstration and Commercial Gas Reburning System Upgrade, Clean Air '96, Orlando, Florida, November 19-22, 1996.

7. D. K. Moyeda, et. al., Experimental/Modeling Studies of the Use of Coal-Based Reburning Fuels for NO_x Control, Twelfth International Pittsburgh Coal Conference, Pittsburgh, Pennsylvania, September 11-15, 1995.

8. K.T. Wu, et. al., Development and Application of a Gas Reburning Process Model for the Design of Boiler NO_x Reductions, Joint Power Generation Conference, San Diego,

California, October 6-10, 1991.

9. B. A. Folsom, et. al., Demonstration of "Gas Reburning-Low NO_x Burner Technology for Cost Effective NO_x Emission Control, Fourth Annual Clean Coal Conference, Denver, Colorado, September 5-8, 1995.

THE NOXSO CLEAN COAL PROJECT

James B. Black
Mark C. Woods
John J. Friedrich
John P. Browning

NOXSO Corporation
2414 Lytle Road
Bethel Park, PA 15102

ABSTRACT

The NOXSO Clean Coal Project will consist of designing, constructing, and operating a commercial-scale flue-gas cleanup system utilizing the NOXSO Process. The process is a waste-free, dry, post-combustion flue-gas treatment technology which uses a regenerable sorbent to simultaneously adsorb sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from flue gas from coal-fired boilers. The NOXSO plant will be constructed at Alcoa Generating Corporation's (AGC) Warrick Power Plant near Evansville, Indiana and will treat all the flue gas from the 150-MW Unit 2 boiler. The NOXSO plant is being designed to remove 98% of the SO_2 and 75% of the NO_x when the boiler is fired with 3.4 weight percent sulfur, southern-Indiana coal. The NOXSO plant by-product will be elemental sulfur.

The elemental sulfur will be shipped to Olin Corporation's Charleston, Tennessee facility for additional processing. As part of the project, a liquid SO_2 plant has been constructed at this facility to convert the sulfur into liquid SO_2. The project utilizes a unique burn-in-oxygen process in which the elemental sulfur is oxidized to SO_2 in a stream of compressed oxygen. The SO_2 vapor will then be cooled and condensed. The burn-in-oxygen process is simpler and more environmentally friendly than conventional technologies. The liquid SO_2 plant produces 99.99% pure SO_2 for use at Olin's facilities.

The $82.8 million project is co-funded by the U.S. Department of Energy (DOE) under Round III of the Clean Coal Technology program. The DOE manages the project through the Pittsburgh Energy Technology Center (PETC).

I. INTRODUCTION

The NOXSO Process is a waste-free, dry, post-combustion flue-gas cleanup technology which uses a regenerable sorbent to simultaneously adsorb SO_2 and NO_x from flue gas from coal-fired utility and industrial boilers. In the process, the SO_2 is converted to a saleable sulfur by-product (liquid SO_2, elemental sulfur, or sulfuric acid) and the NO_x is converted to nitrogen and oxygen. Since SO_2 and NO_x removal occur at normal flue-gas temperatures (downstream of the combustion air preheater), the NOXSO Process is equally suited for retrofit as well as new installations.

Process development began in 1979 with laboratory-scale tests and progressed to pre-pilot-scale tests (3/4-MW) and a life-cycle test. Each of these test programs [1,2,3] has provided data necessary for the process design. Tests of the NO_x recycle concept, which is inherent to the NOXSO Process, have been conducted on small boilers at PETC and at the Babcock & Wilcox (B&W) Research Center in Alliance, Ohio [4].

A 5-MW Proof-of-Concept (POC) pilot-plant test at Ohio Edison's Toronto Plant in Toronto, Ohio, was completed in 1993 [5]. Based on more than 7,000 hours of operation with flue gas, it was demonstrated the process can economically remove more than 95% of the acid rain precursor gases from the flue-gas stream.

The NOXSO Clean Coal Project is the final step in commercialization of the technology. The project was selected during Round III of the DOE Clean Coal Technology Program and is managed through PETC. NOXSO Corporation is the project participant, project manager and technology supplier. The project is being hosted by AGC at their Warrick Power Plant (WPP) near Evansville, Indiana. Morrison Knudsen Corporation is providing engineering services. Projex Inc. is managing construction of the facility.

Final processing of the sulfur by-product to make liquid SO_2 will be completed at Olin Corporation's Charleston, Tennessee facility. The SO_2 plant which utilizes a unique burn-in-oxygen process for converting sulfur to liquid SO_2 is complete. The burn-in-oxygen process is simpler and more environmentally friendly than conventional technologies. Midwest Technical, Inc. provided engineering services. Projex, Inc. managed construction of the facility.

Design and procurement activities are currently being conducted for the NOXSO plant. Preliminary construction activities were completed during the fall of 1996, with full-scale construction scheduled to begin in February 1997. Mechanical completion will occur in June 1998. After commissioning and start-up, the plant will be operated for two years as part of the Clean Coal Project.

Meanwhile, mechanical completion, testing and start-up of the liquid SO_2 plant was achieved in December 1997. Feedstock sulfur will be purchased on the market until the start-up of the NOXSO plant, at which time the NOXSO plant will be the sole source of feedstock for the liquid SO_2 plant. Operating and environmental data will be collected during the plant's operation.

Funding for the $82.8 million project will be provided by the DOE, NOXSO, AGC, Warrick County, the Southern Indiana Gas and Electric Company (SIGECO), the Gas Research Institute (GRI), W.R. Grace, and the Electric Power Research Institute (EPRI). NOXSO will raise most of its project funds through the sale of revenue bonds issued and guaranteed by the state of Indiana. The guarantee is made possible by state legislation signed into law on March 28, 1995. NOXSO will repay the bonds from revenue generated by the sale of SO_2 allowances and by the sale of liquid SO_2 to Olin during a thirteen-year time period which includes the two-year demonstration operation period.

II. THE NOXSO COMMERCIAL DEMONSTRATION PLANT

The objective of the NOXSO Clean Coal Technology Project is to design, construct, and operate a

NOXSO plant at commercial scale. At the completion of this project, the performance, operability, reliability, construction cost, and operating cost data will be available to assist utilities in making decisions regarding the choice of flue-gas cleanup technology.

Host Site Information

The WPP is owned by AGC and operated by the Southern Indiana Gas and Electric Company (SIGECO). The plant supplies electricity to Alcoa's adjacent Warrick Operations aluminum facility and to the utility grid. The WPP consists of three coal-fired steam electric generating units (Units 1, 2, and 3), each rated at 150 MW, and Unit 4, rated at 300 MW. Unit 4 is jointly owned by AGC and SIGECO. Approximately 80% of the electric power generated at WPP is used by Warrick Operations with the remainder being sent to the utility grid.

As shown in Figure 1, the WPP is located in Warrick County, about 15 miles east of Evansville, Indiana, on Indiana Route 66. The WPP and Warrick Operations are located on approximately 600 acres of land between Indiana Route 66 and the Ohio River.

High sulfur Squaw Creek coal with composition as shown in Table 1 will be burned in Unit 2 after the NOXSO plant is installed. Squaw Creek coal is currently blended with a low sulfur coal for use in Units 1, 2, and 3 to satisfy the Warrick County State Implementation Plan (SIP) limit of 5.11 pounds SO_2 per million Btu of heat input.

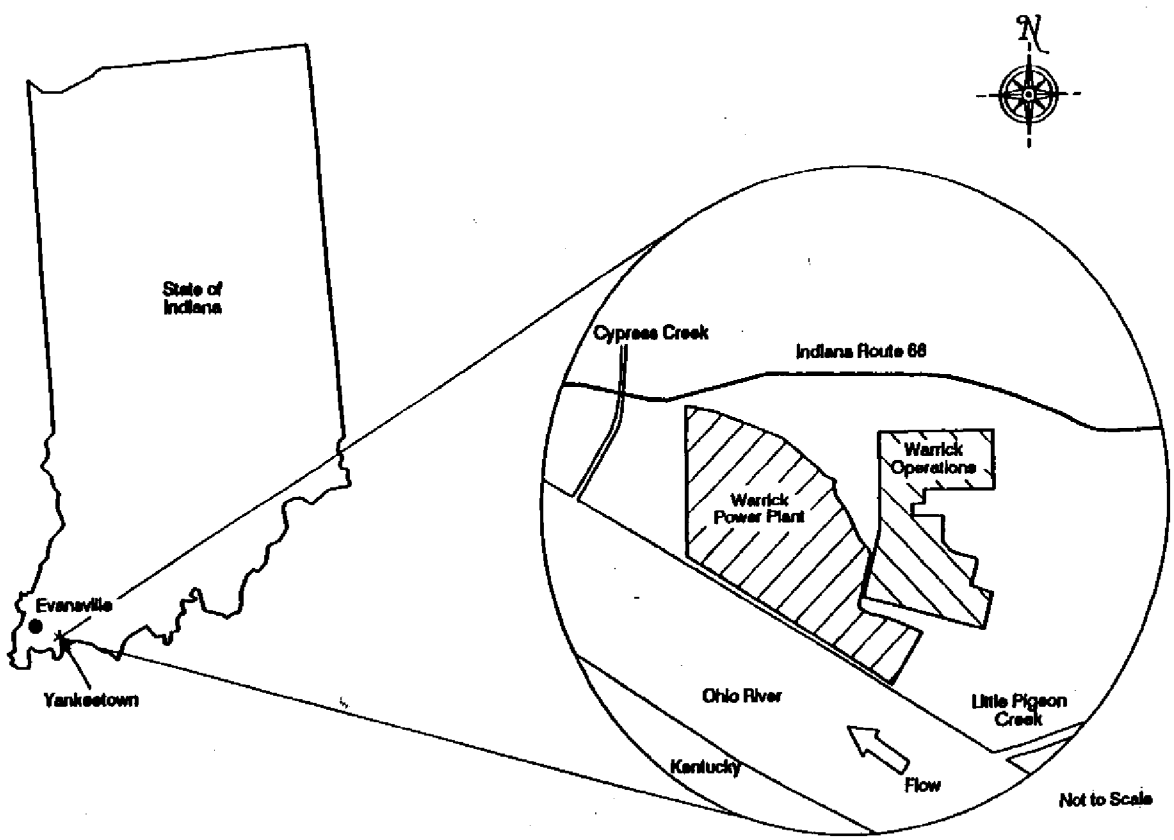


Figure 1. Warrick Power Plant and Warrick Operations Site Location

Parameter	Weight Percent (%)
Moisture	12.92
Carbon	62.02
Hydrogen	4.58
Nitrogen	1.22
Chlorine	0.05
Sulfur	3.39
Ash	8.23
Oxygen	7.60
Higher Heating Value (HHV) (Btu/lb)	11,307

Table 1. Squaw Creek Coal - Ultimate Analysis

AGC has opted-in WPP Units 1, 2, and 3 to the Acid Rain Program of the Clean Air Act (CAA) Amendments of 1990. The Opt-In Program (40 CFR Part 72) allows nonaffected sources, such as AGC's WPP Units 1, 2, and 3, to enter the SO_2 portion of the acid rain program and receive SO_2 emission allowances.

Table 2 shows the design parameters for Unit 2. The wall-fired unit built by Babcock & Wilcox Company (B&W) was placed into service in 1964. The boiler is a natural circulation, Carolina-type radiant unit with 16 circular coal burners arranged in a 4-by-4 grid on a single furnace wall. Coal is reduced from 3/4 inches (in) to 60% less than 200 mesh by B&W EL-76 ball and race pulverizers.

Boiler Manufacturer	Babcock & Wilcox
Operation Date	1964
Primary Fuel	Coal
Start-up Fuel	Natural gas with co-fire
Boiler Type	Wall-fired, natural circulation, Carolina-type radiant unit
Nameplate Rate	144 MW
Steam Flow	1,000,000 lb/hr
Steam Temperature	1,005°F
Design Pressure	1,975 psig
Turbine/Generator Set	160 MW
Existing Burners	16 wall-fired burners
Particulate Control	Western Precipitator electrostatic precipitator designed for 1.83 grains/acfm outlet dust for 688,600 acfm flue gas at 710°F

Table 2. Unit 2 Design Parameters

NOXSO Process Description

The NOXSO Process is a dry, post-combustion flue-gas treatment technology which will use a regenerable sorbent to simultaneously adsorb SO_2 and NO_x from the flue gas from Unit 2 of AGC's WPP. In the process, the SO_2 will be converted to liquid SO_2 and the NO_x will be reduced to nitrogen and oxygen. The NOXSO plant is designed to remove 98% of the SO_2 and 75% of the NO_x. Details of the NOXSO Process are described with the aid of Figure 2.

Flue gas from the power plant is drawn through two flue-gas booster fans which force the air through two fluid-bed adsorbers and a baghouse before passing to the power plant stack. For simplicity, only one adsorption train is shown in Figure 2. Water is sprayed directly into the adsorber fluid beds as required to lower the temperature to 250-275°F by evaporative cooling. The fluid-bed adsorber contains active NOXSO sorbent. The NOXSO sorbent is a 1.2 mm diameter stabilized γ-alumina bead impregnated with sodium. The baghouse removes sorbent which may be entrained in the flue gas and directs it to the fly ash sluicing system.

Spent sorbent from the adsorbers flows into a dense-phase conveying system which lifts the sorbent to the top bed of the sorbent heater vessel. The sorbent flows through the four-stage fluidized-bed sorbent heater in counterflow to the heating gas which heats the sorbent to the regeneration temperature of approximately 1150°F.

In heating the sorbent, the NO_x is driven off and carried to the power plant boiler in the NO_x recycle stream. The NO_x recycle stream is cooled from approximately 360°F to 140°F in the feedwater heater. This heat-exchanger heats a slip stream of the power plant's feedwater, thereby reducing the amount of extraction steam taken from the low pressure turbine, enabling the generation of additional electricity. The cooled NO_x recycle stream replaces a portion of the combustion air. The presence of NO_x in the combustion air suppresses the formation of NO_x in the boiler resulting in a net destruction of NO_x.

The heated sorbent is transported through an L-valve to the steam disengaging vessel. Transport steam is separated from the sorbent to reduce the volume of the regenerator off-gas stream. Sorbent gravity flows into the regenerator where it is contacted with natural gas. Through a series of chemical reactions, the sulfur on the sorbent combines with the methane and forms SO_2 and H_2S. Additional regeneration occurs in the steam treater section of the regenerator when the

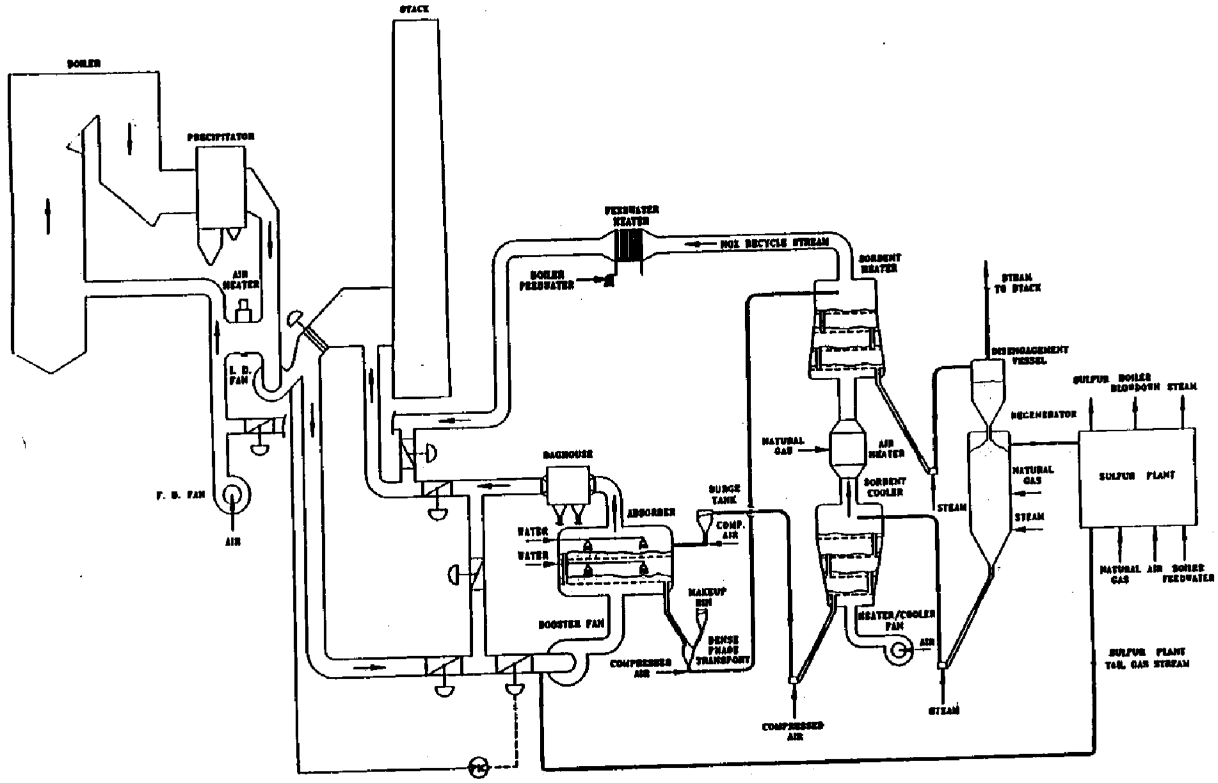


Figure 2. NOXSO Process Diagram - Alcoa Generating Corporation Warrick Plant Unit 2

sorbent is contacted with steam, converting the remaining sulfur on the sorbent to H_2S. The regenerator off-gas stream is directed to a sulfur recovery plant where the H_2S and SO_2 are converted to elemental sulfur. Tail gas from the sulfur recovery plant will be oxidized and recycled back through the adsorbers to remove any residual sulfur compounds.

High temperature sorbent exiting the regenerator is conveyed with an L-valve to the four-stage fluidized-bed sorbent cooler. The sorbent flows counter to the ambient air which cools the sorbent. Regenerated sorbent exits the cooler at 320°F. The sorbent is then conveyed through an L-valve to the sorbent surge tank before being returned to the adsorber, completing the sorbent cycle.

Ambient air which is forced through the sorbent cooler by the heater-cooler fans exits the sorbent cooler at approximately 950°F. This preheated air then enters the air heater where it is heated to approximately 1340°F. The high temperature air is used in the sorbent heater to heat the sorbent to the regeneration temperature of 1150°F.

NOXSO Plant Description

The Demonstration Plant will be located in a generally unoccupied area of the plant yard south of Unit No. 2. This area requires minimal site preparation and provides adequate space for the NOXSO plant while offering a convenient tie-in point for the flue-gas ductwork, see Figure 3, since the existing flue-gas plenum and plant stacks are located on the south side of the power plant. This location also provides plant access from the south for sorbent and nitrogen delivery while the sulfur recovery unit is accessible by rail and road. The general arrangement is shown in Figure 4.

The NOXSO plant will take up an area approximately 250' × 200' in size, just south of Precipitator Road, which is an east-west running plant access road south of the power plant. The analyzer and control building is located to the east of the NOXSO plant while the sulfur recovery unit is situated to the west, at the southern end of the battery limits.

The locations of the major process vessels within this area are chosen to minimize the amount of ductwork required to deliver and return the flue gas, and to minimize the horizontal distances that the sorbent must travel between vessels. Thus, the adsorption trains, including booster fans, adsorbers, and baghouses, are situated furthest north within the battery limits. The adsorption trains are shown in the foreground of Figure 4. The adsorbers, like the regenerator and sorbent cooler, are self-supporting vessels through the use of vessel skirts which reduce the overall amount of structural steel required.

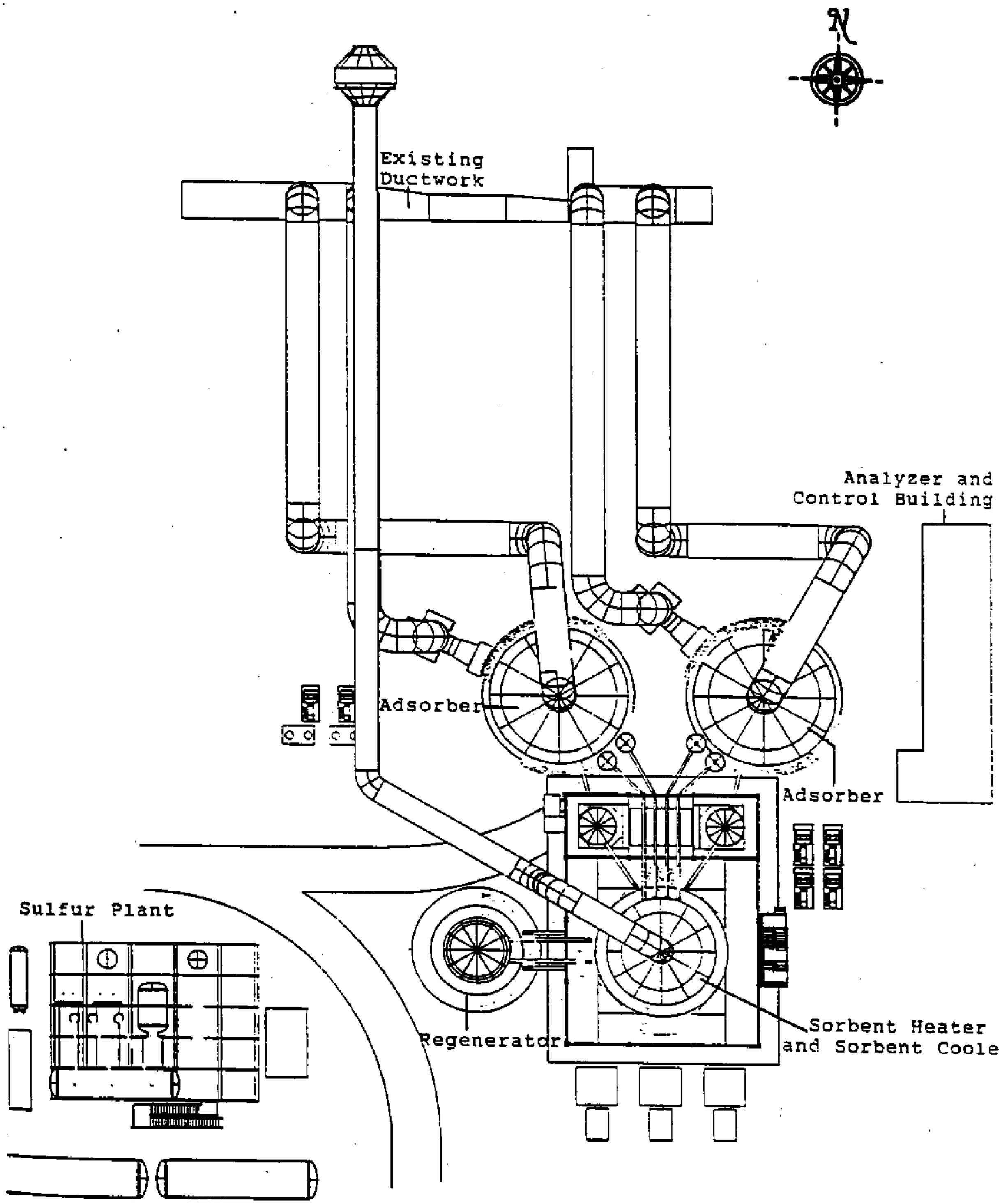


Figure 3. Plant Layout

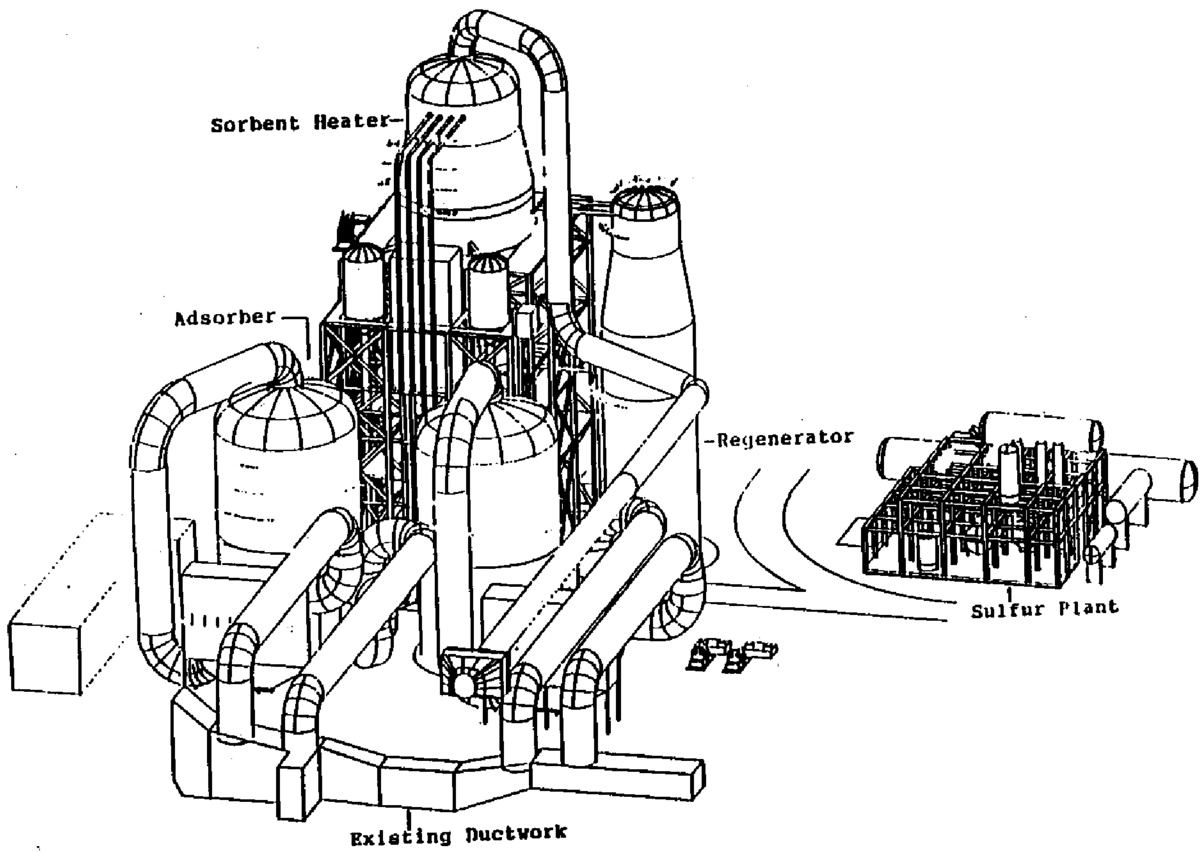


Figure 4. General Arrangement

The regeneration train, consisting of the sorbent heater, steam disengaging vessel, regenerator and sorbent cooler, is just south of the adsorption trains. The sorbent cooler and sorbent heater are in a stacked arrangement, so that the heat energy recovered by the fluidizing air in the sorbent cooler may be used in the sorbent heater. The sorbent cooler, hidden by the structural tower in Figure 4, is skirt supported on the ground, while the sorbent heater is supported 95' in the air at its base by the sorbent heater tower. This tower is centered behind and situated as close as possible to the two adsorbers to minimize the horizontal distance that the sorbent must travel between the two trains.

The regenerator and steam disengaging vessel are in a stacked arrangement to allow gravity flow of the sorbent between the two vessels. Again, to minimize the horizontal sorbent conveying distance, the regenerator is situated as close as possible to the sorbent heater tower. The regenerator is located on the west side of the tower because of space availability for the sulfur recovery unit, which is to the west of the regenerator. It is essential to position the sulfur recovery unit as close as possible to the regenerator to limit the distance of the steam-traced, regenerator off-gas line.

III. THE LIQUID SO_2 FACILITY

As discussed previously, the purpose of the NOXSO Clean Coal Project is to demonstrate the NOXSO flue-gas treatment system in a fully integrated commercial scale operation. The NOXSO plant will reduce SO_2 and NO_x emissions from Alcoa Generating Corporation's Warrick Power Plant Unit 2. The removed sulfur will be processed into elemental liquid sulfur. In addition, as part of the project, a liquid SO_2 plant has been constructed at Olin Corporation's Charleston, Tennessee facility to convert the sulfur into liquid SO_2.

Host Site Information

Figure 5 is a site plan of the Olin Charleston Plant (OCP). There are five basic areas within the plant: administration, including process technology and product quality/environmental control buildings; chlor-alkali, consisting of chlorine/caustic soda production facilities, Reductone® (sodium hydrosulfite) production facilities, hydrochloric acid production facilities, boiler house, and water treatment; HTH® Dry Chlorinator (calcium hypochlorite) production facilities and associated warehousing; rubber services, and associated warehousing; and maintenance facilities.

As shown in Figure 6, OCP is located in Bradley County, in southeastern Tennessee about 12 miles northeast of Cleveland, Tennessee. Charleston, Tennessee, the closest town to the site, is 1.5 miles southeast of the plant. The OCP consists of roughly 975 acres between Lower River Road and the Hiwassee River (which flows to the northwest). Liquid SO_2 is a primary feedstock at the OCP where it is used to produce sodium hydrosulfite which is sold to the paper industry where it is used as a bleach for paper and clay.

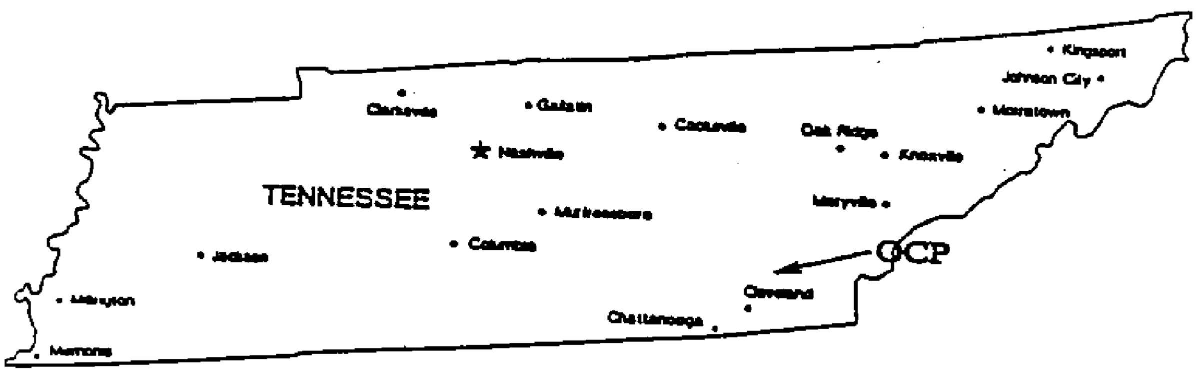


Figure 5. OCP Location

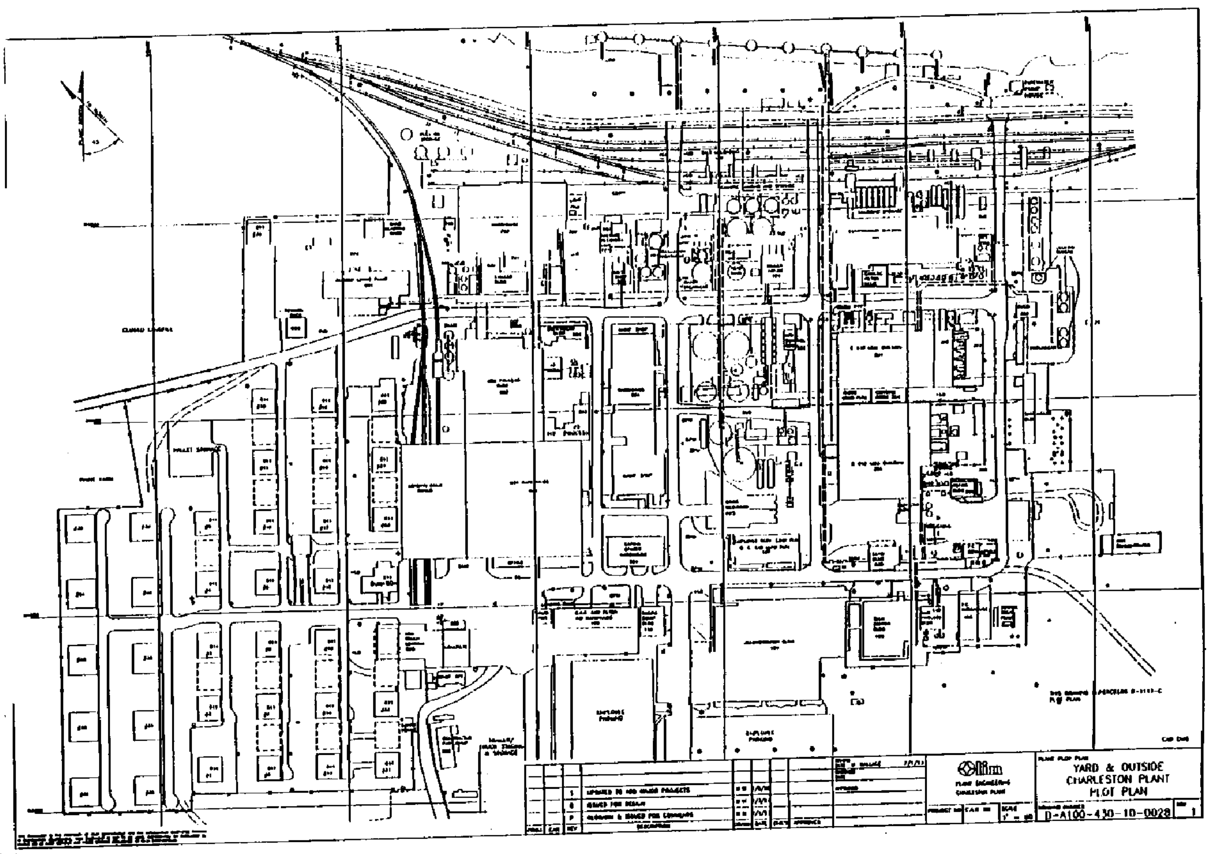


Figure 6. OCP Site Plan

Liquid SO_2 Process Description

The liquid SO_2 facility consists of two components, the liquid SO_2 plant and a cryogenic air separation plant. The facility is located on less than an acre of Olin property east of the existing switchgear building. Figure 7 presents the site plan for the liquid SO_2 facility detailing its relationship within Olin's plant site.

The SO_2 plant, the primary aspect of the liquid SO_2 facility, is an advanced liquid SO_2 production process designed for ease of operation and maintenance and to minimize process waste streams and emissions to the environment. Reliable operation of a 9,000 tpy commercial unit over the last five years has demonstrated and proven the technology. In the basic process, molten sulfur is oxidized to SO_2 vapor in compressed oxygen. The SO_2 vapor is then separated from vaporized sulfur and condensed. Key resources, including molten sulfur, oxygen (O_2), and caustic, are fed to the process. The process in turn produces liquid SO_2, steam, and sodium sulfite.

The cryogenic air separation plant provides 99.5% O_2 to the liquid SO_2 plant. The oxygen is produced by liquefying air and then using fractional distillation to separate it into its components. The air separation plant requires inputs of air, electricity, and cooling water and produces, in addition to the O_2, a small amount of pure nitrogen (N_2).

Liquid SO_2 Plant Description

The facility will have the operating capacity to produce about 125 tpd (45,000 tpy) of liquid SO_2. Figure 8 presents a basic flow diagram of the liquid SO_2 process. Primary unit operations are numerically labelled on this figure and referenced in the following discussion. Liquid sulfur at about 270°F is continuously pumped from two-250 ton capacity sulfur storage tanks (1) to the sulfur day tank (2). Sulfur flows by gravity from the day tank to the SO_2 reactor (3). The sulfur level in the reactor is controlled by equalization with the level in the sulfur day tank.

During start up the sulfur in the reactor is electrically heated to about 600°F. Oxygen is then injected into the sulfur through a submerged sparger. The sulfur at the reactor operating pressure, 80 psig and 600°F, is above the auto-ignition temperature. The following reaction occurs:

$$S + O_2 \rightarrow SO_2$$

The reaction is spontaneous and exothermic. The reactor temperature rises to about 1100°F, the boiling point of sulfur at 80 psig. The production rate of SO_2 is controlled by the oxygen feed rate to the reactor.

The vapor stream of SO_2 and sulfur is cooled in the sulfur condenser (4) to about 270°F. The condenser is cooled by generating steam at 35 psig. Most of the sulfur vapor condenses and the mixture of condensed sulfur, which flows by gravity, and SO_2 vapor is returned to the molten sulfur day tank. The liquid sulfur drops out in the sulfur day tank and is recycled to the reactor.

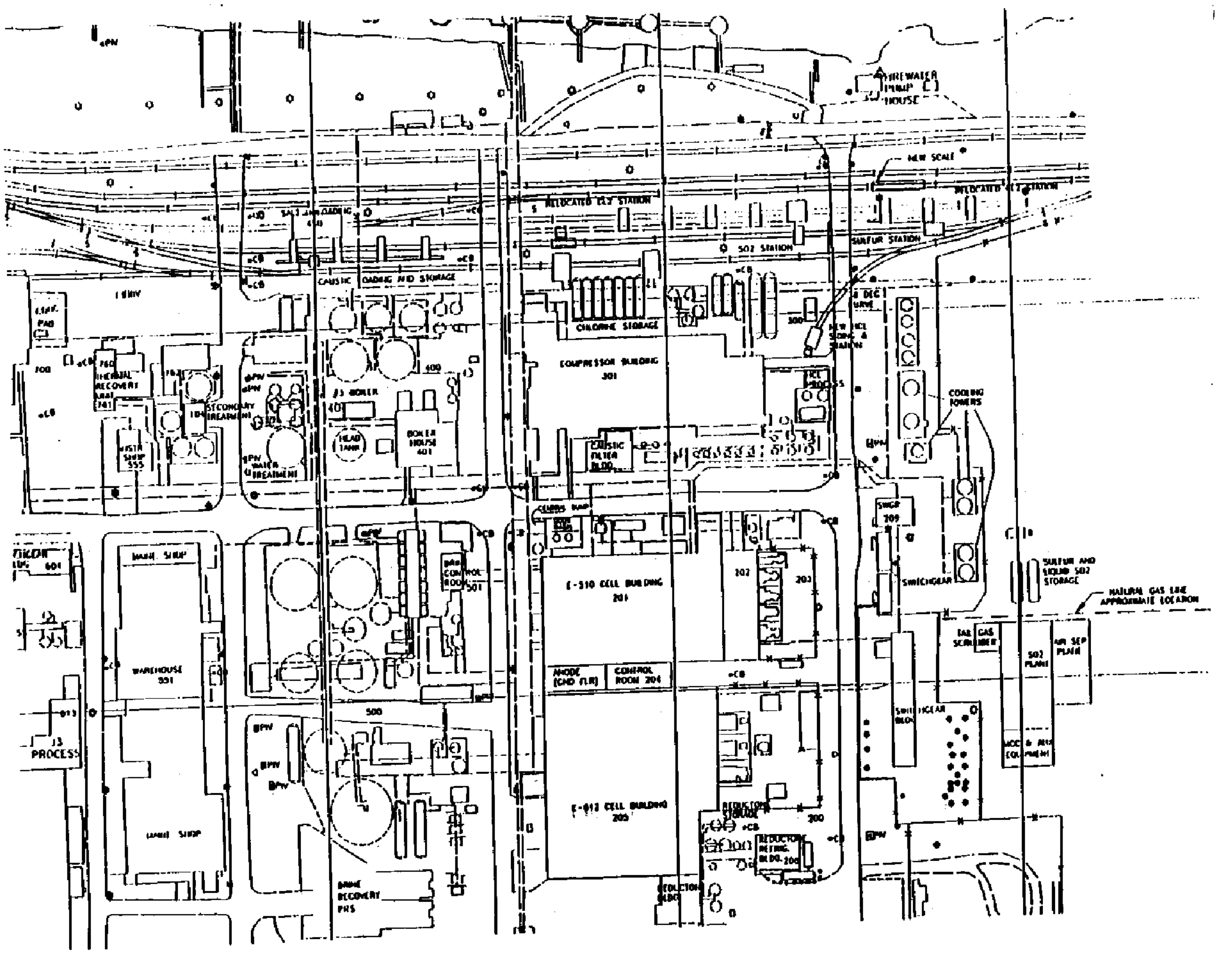


Figure 7. Liquid SO2 Facility

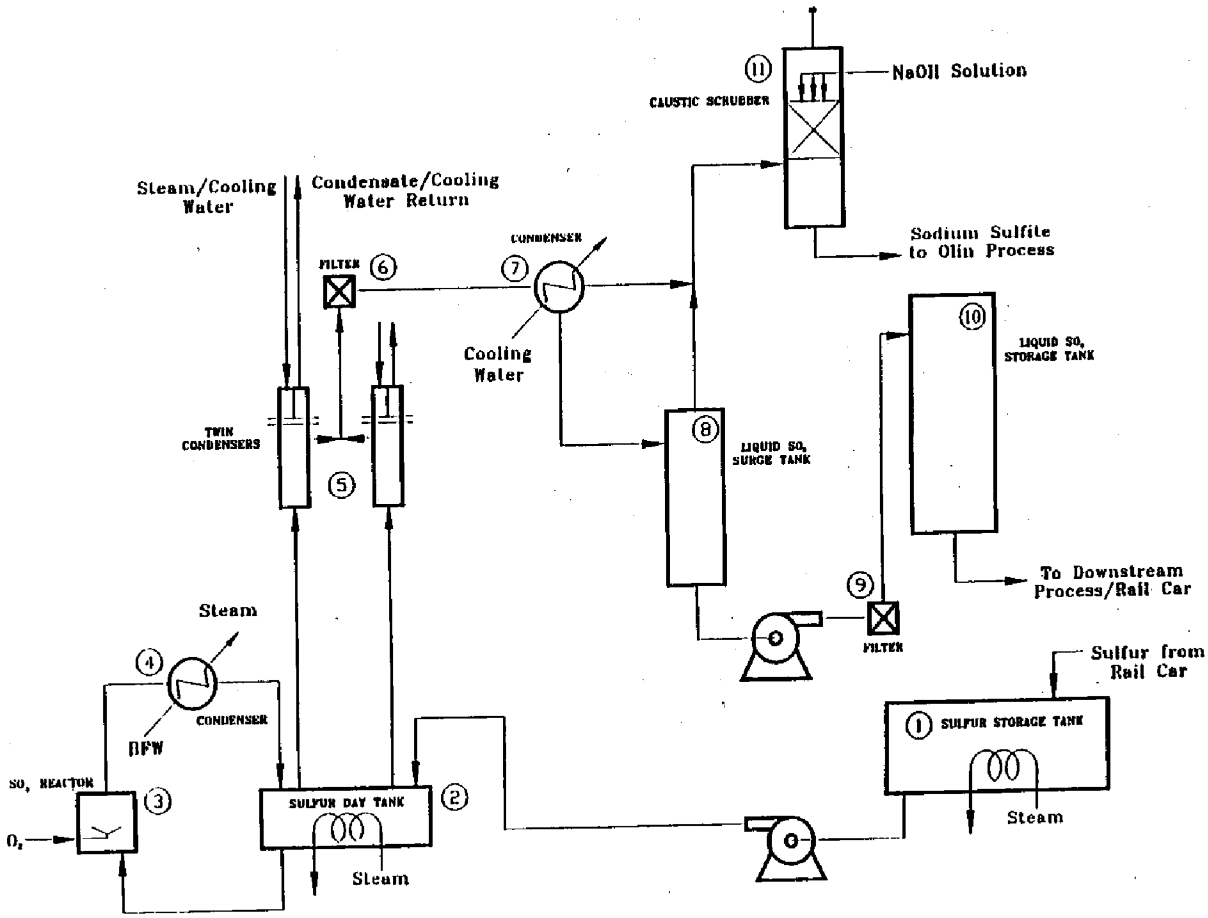


Figure 8. Liquid Sulfur Dioxide Process

The SO_2 vapor does not condense at 270°F and is not significantly soluble in molten sulfur. It is further cooled in the twin condensers (5) to remove additional trace amounts of sulfur. The condensers operate in a two step repeating cycle. In the first step, the condenser cools the SO_2 to 120°F using cooling water. Entrained liquid sulfur and remaining sulfur vapor will collect as a solid on the condenser tube walls. In the second step, the condenser gas outlet is blocked and the sulfur is melted using low pressure steam. The molten sulfur will drain by gravity back to the sulfur day tank. The condensers will alternate between these modes of operation; one condenser will remove sulfur while the second condenser is regenerated using steam.

After filtration (6), the SO_2 vapor is condensed in the SO_2 condenser (7) using cooling water. At the system pressure of 80 psig, the SO_2 condenses at about 104°F. The liquid SO_2 will flow to the liquid SO_2 surge tank (8). From the surge tank it will be pumped through a filter (9) to remove any entrained particulate then to a 200-ton capacity liquid SO_2 storage tank (10). From the storage tank, the liquid SO_2 will be pumped to an existing process liquid SO_2 feed tank or to rail cars for shipment.

A vent stream from the SO_2 condenser and liquid SO_2 surge tank contains non-condensibles, trace amounts of nitrogen and argon introduced to the sulfur reactor with the oxygen, and SO_2 vapor. The SO_2 vapor is removed from the vent stream in a caustic scrubber (11). A sodium hydroxide (NaOH) solution is used to remove the SO_2 vapor from the gas stream. The sodium sulfite formed from the reaction of NaOH and SO_2 will be used by Olin to neutralize a chlorine waste stream from an existing Olin process.

Air Separation Plant Description

Figure 9 presents a basic flow diagram of the air separation plant used to supply O_2 to the liquid SO_2 process. Primary unit operations are numerically labelled on this figure and referenced in the following discussion. As mentioned previously, oxygen is produced by liquefying air and then using fractional distillation to separate the liquefied air into its components. The three fundamental steps in this process are purification, refrigeration, and rectification.

Purification

Atmospheric air contains dirt, water vapor, and carbon dioxide (CO_2) which must be removed from the compressed air stream to prevent plugging of downstream process equipment. The atmospheric air passes through an intake filter (1) to remove entrained particulate and is compressed to 125 psig in a centrifugal compressor (2). After compression the air is cooled in a direct contact after cooler (3) using cooling water. Carbon dioxide, water vapor, and gaseous hydrocarbons are then removed by adsorption on activated alumina and molecular sieve (4). Parallel units are used, like the twin condensers from the liquid SO_2 process, one bed will be regenerated while the other is online. The adsorbents are regenerated using heat and a nitrogen purge gas generated downstream.

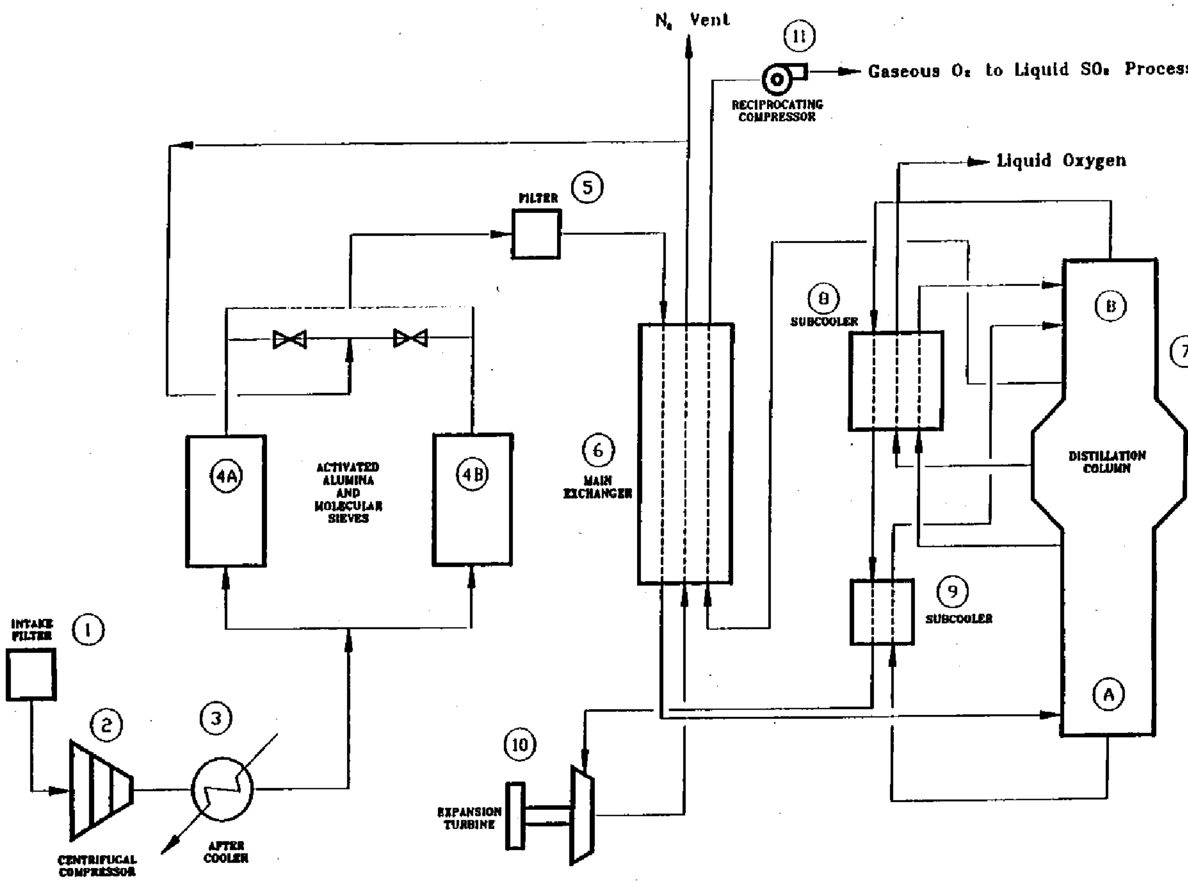


Figure 9. Air Separation Plant

Refrigeration/Rectification

The purified air passes through a pipeline filter (5) and enters the main exchanger (6) where it is cooled by heat exchange with outgoing gaseous oxygen and waste gas. After the main exchanger, the purified air enters the bottom section of the lower column (7A) of the distillation column (7). The lower column operates at about 60 psig while the upper column (7B) of the distillation column operates at about 5 psig. Rectification, vapor - liquid contacting, occurs in the distillation column. As the incoming air rises up the column, it contacts a descending liquid. Since oxygen has a higher boiling point than nitrogen, as the vapor ascends it becomes richer in nitrogen while as the liquid descends it becomes richer in oxygen. Cold nitrogen rich vapor is withdrawn from several places within the distillation column and used to cool recycle streams in the subcoolers (Units 8 & 9). Heat energy is also removed from the system by expanding the nitrogen rich vapor in the expansion turbine (Unit 10), thereby doing work and lowering the temperature. Pure oxygen vapor is withdrawn from the bottom of the upper column. This vapor is warmed in the main exchanger and compressed using a reciprocating compressor (11) to the required operating pressure.

Process Alternatives/Advantages

Traditional, older processes used to produce liquid SO_2 from sulfur involve burning the sulfur in air. The resulting gas stream can contain, at best, 16-18 vol.% SO_2 with the balance being mainly nitrogen, oxygen, and water from the combustion air. The SO_2 must then be separated from the other combustion gases. This is done by stripping the SO_2 from the gas stream using either water or an organic solvent like dimethylaniline. Regardless of which stripping liquor is used, these processes are more complex and have greater environmental impacts. To illustrate, the burn in air with water stripping process.

Process advantages of the burn-in-oxygen liquid SO_2 process include the following:

- Process gas at a lower temperature, 1100°F versus about 2500°F.
- Production of lower pressure steam, 35 psig versus 600 psig.
- No acidic wastewater stream which must be neutralized.
- Smaller volume tail gas stream which economically allows for the use of a more efficient scrubber resulting in lower SO_2 emissions.
- No spent acid stream which must be reclaimed or disposed of.
- No solvent emissions or disposal of solvent.

In addition, due to the lower process gas temperature and steam pressure, and simplicity of the process the liquid SO_2 process is inherently more reliable and safe to operate.

IV. ACKNOWLEDGEMENT

The authors wish to thank the following for their contributions to the project: U.S. Department of Energy, Alcoa Generating Corporation, State of Indiana, Indiana Development Finance Authority, Warrick County, Olin Corporation, the Electric Power Research Institute, and the Gas Research Institute.

V. REFERENCES

1. Haslbeck J.L., C.J. Wang, Neal L.G., Tseng H.P., and J.D. Tucker, "Evaluation of the NOXSO Combined NO_x/SO_2 Flue Gas Treatment Process," U.S. Department of Energy Contract NO. DE-AC22-FE60148, (November 1984).
2. Haslbeck, J.L., W.T. Ma, and L.G. Neal, "A Pilot-Scale Test of the NOXSO Flue Gas Treatment Process," U.S. Department of Energy Contract No. DE-FC22-85PC81503, (June 1988).
3. Ma W.T., J.L. Haslbeck, and L.G. Neal, "Life Cycle Test of the NOXSO Process," U.S. Department of Energy Contract NO. DE-FC22-85PC81503, (May 1990).
4. Zhou Q., J.L. Haslbeck, and L.G. Neal, "An Experimental Study of NO_x Recycle in the NOXSO Flue Gas Cleanup Process," U.S. Department of Energy Contract No. DE-AC22-91C91337, (March 1993).
5. Haslbeck J.L., M.C. Woods, W.T. Ma, S.M. Harkins, and J.B. Black, "NOXSO SO_2/NO_x Flue Gas Treatment Process: Proof-of-Concept Test," presented at the SO_2 Symposium, Boston, MA (August 1993).

Integrated Dry NO_x/SO_2 Emissions Control System Performance Summary

Terry Hunt
Public Service Company of Colorado
Denver, Colorado 80207

Lawrence J. Muzio, Randall Smith
Fossil Energy Research Corp.
Laguna Hills, California 92653

Dale Jones[1]
NOELL, Inc.
Long Beach, California 90806

Jerry L. Hebb
U. S. Department of Energy
Pittsburgh, Pennsylvania 15236

Jeff Stallings
Electric Power Research Institute
Palo Alto, California 94303

ABSTRACT

The Integrated Dry NO_x/SO_2 Emissions Control System was installed at Public Service Company of Colorado's Arapahoe 4 generating station in 1992 in cooperation with the U.S. Department of Energy (DOE) and the Electric Power Research Institute (EPRI). This full-scale 100 MWe demonstration combines low-NO_x burners, overfire air, and selective non-catalytic reduction (SNCR) for NO_x control and dry sorbent injection (DSI) with or without humidification for SO_2 control. Operation and testing of the Integrated Dry NO_x/SO_2 Emissions Control System began in August 1992 and will continue through 1996. Results of the NO_x control technologies show that the original system goal of 70% NO_x removal has been easily met and the combustion and SNCR systems can achieve NO_x removals of up to 80% at full load. Duct injection of commercial calcium hydroxide has achieved a maximum SO_2 removal of nearly 40% while humidifying the flue gas to a 20°F approach to saturation. Sodium-based dry sorbent injection has provided SO_2 removal of over 70% without the occurrence of a visible NO_2 plume. Recent test work has improved SNCR performance at low loads and has demonstrated that combined dry sodium injection and SNCR yields both lower NO_2 levels and NH_3 slip than either technology alone.

INTRODUCTION

Public Service Company of Colorado (PSCC) was selected by DOE for a CTT-III project in December 1989 to demonstrate an Integrated Dry NO_x/SO_2 Emissions Control System. The demonstration project is taking place at PSCC's Arapahoe Unit 4, a 100 MWe top-fired unit

[1] Currently with BTU Services, Visalia, California

which fires a low sulfur (0.4%) Colorado bituminous coal as its main fuel, but also has 100% natural gas capability. Figure 1 shows a boiler elevation drawing.

The Integrated Dry NO_x/SO_2 Emissions Control System combines five major control technologies to form an integrated system to control both NO_x and SO_2 emissions. The system uses low-NO_x burners, overfire air, and urea injection to reduce NO_x emissions, and dry sorbent injection using either sodium- or calcium-based reagents with (or without) humidification to control SO_2 emissions. The goal of the project was to reduce NO_x and SO_2 emissions by up to 70%. The combustion modifications were expected to reduce NO_x by 50%, and the SNCR system was expected to increase the total NO_x reduction to 70%. Dry Sorbent Injection was expected to provide 50% removal of the SO_2 emissions while using calcium-based reagents. Because sodium is much more reactive than calcium, it was expected to provide SO_2 removals of up to 70%. Figure 2 shows a simplified schematic of the Integrated Dry NO_x/SO_2 Emissions Control System at Arapahoe Unit 4.

The total cost of this innovative demonstration project is estimated to be $27,411,000. Funding is being provided by DOE (50%), PSCC (43.7%), and EPRI (6.3%). DOE funding is being provided as a zero interest loan and is expected to be paid back from the proceeds obtained during commercialization of the technology over a 20-year period which begins at the conclusion of the demonstration project.

Construction began in July 1991 and was completed in August 1992. The test program began in August 1992 and all low sulfur coal testing was scheduled for completion in June 1994. Addition of the new SNCR injection location and alternate lance design tests will extend the test program through December 1996. Project completion is currently scheduled for February 1997.

Prior publications presented results of the performance of the individual technologies (1-11). This paper will provide a brief overview of the individual technologies and their performance, but will focus on results from recent test activities. These recent activities have included: 1) testing of a new SNCR injection location to improve low load performance; 2) long term performance of the integrated system; and 3) recent results of ammonia adsorption in the ash.

TECHNOLOGY DESCRIPTION

This section will provide a brief description of the technologies used in the integrated NO_x/SO_2 Emissions Control System with emphasis on the SNCR and sodium dry sorbent injection system. The reader is referred to prior publications for more complete descriptions of the low NO_x combustion system and calcium dry sorbent system with humidification.[1-11]

Low NO_x Combustion System

B&W's DRB-XCL® (Dual Register Burner-aXially Controlled Low-NO_x) burner had been successfully used to reduce NO_x emissions on wall-fired boilers but had never been used in a vertically-fired furnace. The burner utilizes dual registers to control near burner mixing and a sliding air damper to control air flow to each individual burner independent of swirl. Twelve of these burners were installed on the roof of Arapahoe Unit 4. The low NO_x combustion system also incorporated three B&W dual zone NO_x ports which were added to each side of the furnace approximately 20 feet below the boiler roof. These ports can inject up to 28% of the total combustion air through the furnace sidewalls.

Arapahoe Unit 4 was originally designed with the ability to fire 100% natural gas. Natural gas firing capabilities were maintained with the DRB-XCL® burners by installing a gas ring header at the tip of the burner. However, the burner is not specifically designed to be a low-NO_x burner with natural gas firing.

Selective Non-Catalytic Reduction

The purpose of the SNCR system at Arapahoe was two-fold. First, to further reduce the final NO_x emissions obtained with the combustion modification so that the goal of 70% NO_x removal could be achieved. Second, the SNCR system is an important part of the integrated system interacting synergistically with the dry sodium injection system. During this program, it was shown that when both systems are used simultaneously, both NO_2 emissions from the sodium system and NH_3 slip from the SNCR system are reduced.

When the SNCR system was originally designed and installed, it incorporated two levels of wall injectors with 10 injectors at each level. These two separate levels were intended to provide load following capability. The locations of these two levels were based on flue gas temperature measurements made with the original combustion system. However, the retrofit low-NO_x combustion system resulted in a decrease in the furnace exit gas temperature of nominally 200°F. This decrease in temperature moved the cooler injection level out of the SNCR temperature window. With only one operational injection level, the load-following performance of the system was compromised.

Two approaches were pursued to improve the low load performance of the SNCR system. First, short-term testing showed ammonia to be more effective than urea at low loads. Although ammonia was more effective than urea, it remained desirable to store urea due to safety concerns. A system was installed that allows on-line conversion of urea into ammonia compounds. The on-line conversion system improved low load performance, but the improvement was not as large as desired at the lowest load (60 MWe).

More recently, NOELL, Inc. (the original supplier of the SNCR system) suggested an additional injection location in a higher temperature region of the furnace. Because no unit outages were planned, the only option for incorporating an additional injection level was to utilize two existing (but unused) sootblower ports in conjunction with NOELL's Advanced Retractable Injection Lances (ARILs). This location was chosen because the ports existed, not because the temperatures were ideal for SNCR.

Figure 3 shows a diagram of the SNCR system installed at Arapahoe Unit 4. The system uses NOELL's proprietary dual-fluid injection nozzles to distribute the urea uniformly into the boiler. A centrifugal compressor is used to supply a large volume of medium-pressure air to the injection nozzles. The large quantity of air helps to atomize the urea solution as well as provide energy to rapidly mix the atomized solution with the combustion products. The SNCR system includes the option of passing the urea solution over a proprietary catalyst which converts the urea to ammonia-based compounds. This ammonia conversion system was not utilized during the current series of tests described in this paper.

Figure 4 shows the location of the new ARIL lances relative to the two original SNCR injection locations. Level 2 is the location that became unusable as a result of the flue gas temperature decrease after the low-NO_x combustion system retrofit. The ARIL system consists of two retractable lances and two retractable lance drive mechanisms. Each lance is nominally 4 inches in diameter and approximately 20 feet in length. Each lance has a single row of nine injection nozzles spaced on two-foot centers. A single division wall separates the Arapahoe Unit 4 furnace into east and west halves, each with a width of approximately 20 feet. When each lance is inserted, the first and last nozzles are nominally one foot away from the division and outside walls, respectively.

Each injection nozzle is composed of a fixed air orifice (nominally one-inch in diameter), and a replaceable liquid orifice. The liquid orifices are designed for easy removal and cleaning, because they can become plugged. This ability to change nozzles also allows adjustments in the chemical injection pattern along the length of the lance in order to compensate for any significant maldistributions of flue gas velocity, temperature, or baseline NO_x concentration.

Two separate internal liquid piping circuits are used to direct the chemical to the individual injection nozzles in each lance. The four nozzles near the tip of the lance are supplied by one circuit, and the remaining five are supplied by the other. This provides the ability to bias the chemical flow between the "inside" and "outside" halves of each side of the furnace in order to compensate for various coal mill out-of-service patterns. Each lance is also supplied with a pair of internal thermocouples for detecting inside metal temperatures at the tip of the lance.

The retractable lance drive mechanisms were supplied by Diamond Power Specialty Co. (DPSC). The drives are Model IK 525's which have been modified for the liquid and air supply parts. Both remote (automatic) and/or local (manual) insertion and retraction operations are accomplished with the standard IK electric motor and gearbox drive system. A local control panel is provided on each side of the boiler, attached to each ARIL lance drive mechanism. Each panel contains a programmable logic controller for the lance install/retract sequencing and safety interlocks. Each lance can be rotated either manually at the panel, or automatically by the control system during load-following operation. One of the key features of the ARIL lance system is its ability to rotate the lances. As will be discussed, this feature provides a high degree of flexibility in optimizing SNCR performance by varying the flue gas temperature at the injection location by simply rotating the lance.

In addition to NOELL's ARIL lances, an alternate lance design, supplied by Diamond Power Specialty Company, was also evaluated. This alternate lance design represented a simplification to the original ARIL design. The liquid solution is injected through a single pressure atomizer located in the air supply pipe ahead of the lance. This eliminates the internal liquid piping, and spraying at the lance inlet provides evaporative cooling to help cool the lance. In addition, the design prevents air and liquid from being injected in the local region around the boiler when the lances are retracted.

Dry Sorbent Injection

PSCC designed and installed a dry sorbent injection system that can inject either calcium- or sodium-based reagents into the flue gas upstream of the fabric filter. Figure 5 shows a simplified flow diagram of the equipment. The reagent is fed through a volumetric feeder into a pneumatic conveying system. The air and material then pass through a pulverizer where the material can be pulverized to approximately 90% passing 400 U.S. Standard mesh. The material is then conveyed to the duct and evenly injected into the flue gas. After the original results suggested that the duct flue gas temperature was too low for effective SO_2 removal with sodium bicarbonate, the dry injection system was modified to allow injection of sodium-based compounds at the entrance to the air heater where the flue gas temperature is approximately 600°F. The pulverizer can be bypassed allowing calcium hydroxide to be fed from the silos and injected either ahead of the fabric filter or into the boiler economizer region where the flue gas temperature is approximately 1000°F.

To improve SO_2 removal with calcium hydroxide, a humidification system capable of achieving a 20°F approach to saturation temperature has been installed. The system was designed by B&W and includes 84 I-Jet humidification nozzles which can inject up to 80 gpm of water into the flue gas ductwork. The humidifier is located approximately 100 feet ahead of the fabric filter and there is no bypass duct.

Balance of Plant

Besides the major environmental equipment, the project also included required upgrades to the existing plant. A new distributed control system was installed to control the boiler and other pollution control equipment added as part of the integrated system. The fly ash collection system was also converted from a wet to a dry collection system to allow dry collection of the ash and injection waste products. A Continuous Emissions Monitor (CEM) system was installed at Arapahoe Unit 4 to collect data for the extensive test program. This monitor allows measurements of N_2O, NH_3, NO_2, and H_2O in addition to the more common pollutants.

RESULTS

Fossil Energy Research Corporation (FERCo) of Laguna Hills, California, has been performing all testing of the Integrated Dry NO_x/SO_2 Emissions Control System. The test program is nearing completion and the individual testing of the low-NO_x burners, overfire air, urea injection, calcium duct injection, calcium economizer injection, and sodium injection has been completed. Testing of the SNCR lances and the complete integrated system while firing low-sulfur coal is in progress. In addition to efficiency and emissions measurements, four tests were conducted to determine baseline and removal capabilities of the system for many common air toxic emissions. Prior papers (1-11) also discussed the performance of the individual technologies. This paper will overview these prior results and focus on the performance of the new SNCR injection lances and the performance of the integrated system. In addition, the paper will also present some recent information on NH_3 absorption on fly ash and the impacts on fly ash handling.

Review of NO_x and SO_2 Reduction Performance

This section will provide a brief overview of the NO_x and SO_2 reductions from the individual technologies used in the integrated system. The reader is referred to prior publications for more detailed discussions (1-11).

Low-NO_x Combustion System Performance

The following section describes the performance of the low-NO_x combustion system (low-NO_x burners and OFA ports).

Low-NO_x Burners

Figure 6 compares the Arapahoe Unit 4's NO_x emissions before and after the retrofitting of the low-NO_x combustion system. Note, NO_x (NO + NO_2) and NO are used interchangeably when discussing the performance of the combustion system, since NO_2 levels are very low for this unit. The original combustion system produced nearly uniform NO_x emissions of 800 ppmc (corrected to 3% O_2, dry) or 1.1 lb/MMBtu across the boiler's load range. The low-NO_x combustion system reduced NO_x emissions by over 63 percent, to less than 300 ppmc, across the boiler's load range. Note that all testing was conducted under steady-state conditions and with the careful supervision of test technicians to achieve the maximum possible reduction in NO_x emissions. Under load following conditions, NO_x emissions were about 10 to 25% higher. Additional modifications to the control system and additional operator training may decrease the difference.

Overfire Air

At full load, opening the OFA control dampers to full open (maximum OFA) diverts about 24% of the total combustion air to the OFA ports and at low load (60 MWe) it diverts about 28% of the combustion air. At maximum OFA, the low-NO_x combustion system reduces NO_x emissions by 62 to 69% across the load range. Since the OFA ports are located in a very hot part of the boiler, a significant amount of cooling air is required and the minimum amount of OFA is limited to about 15% of the total combustion air at full load and about 8% at low load. At minimum OFA, the retrofitted combustion system reduces NO_x emissions by 60 to 63%. Arapahoe Unit 4 cannot be tested at 0% OFA, but the small difference in NO_x reduction between maximum and minimum OFA indicates that the low-NO_x burners are responsible for most of the NO_x reduction.

SNCR System Performance

As mentioned previously, in addition to reducing NO_x emissions significantly, the low-NO_x combustion system also reduced the temperature of flue gas at the furnace exit by about 200°F. Since SNCR systems are very sensitive to changes in flue-gas temperatures, this reduction made the flue-gas temperature too cold for one row of injection nozzles, so all testing was performed using the row of injection nozzles originally designed for loads below 80 MWe. Figure 7 shows the SNCR performance achievable over the load range for a 10 ppm NH_3 slip limit with this single row of injectors. At full load, NO_x reductions of 45% are achieved. However, the performance decreased dramatically as the load decreased; at 60 MW, NO_x removals were limited to 11% for a 10 ppm NH_3 slip.

Calcium-Based Economizer Injection Performance

SO_2 removal has been less than expected with calcium hydroxide injection at the economizer. Initial testing at a Ca/S molar ratio of 2.0 without humidification resulted in SO_2 removals in the range of 5 to 8%. Note that the stoichiometric ratio for the Ca/SO_2 reaction is 1.0, since one mole of Ca reacts with one mole of SO_2 to form calcium sulfate, $CaSO_4$ It was found that the sorbent distribution was very poor, and only approximately one-third of the flue gas was being treated. New nozzles that increased reagent distribution only increased the SO_2 removal to 15% at a Ca/S molar ratio of 2.0. Although distribution of the calcium reagent is far from perfect, it appears that high levels of SO_2 removal are not possible at Arapahoe Unit 4 using the current $Ca(OH)_2$ material, even in areas with high Ca/S molar ratios.

Calcium-Based Duct Injection Performance

Higher SO_2 removal was achieved with duct injection of calcium hydroxide and humidification with SO_2 removals approaching 40% at Ca/S ratios of 2.0 and approach to saturation temperatures of 20 to 30°F. These levels of SO_2 removal are consistent with the prior DOE study at Ohio Edison's Edgewater Station.[13] Immediately after this test, problems developed with the dry fly ash transport system, and it is suspected that the low approach temperature contributed to this problem. Then, after a short period of 24 hour/day testing during load following operation, fabric filter pressure drop significantly increased due to the buildup of a hard ash cake on the fabric filter bags which could not be cleaned during normal reverse air cleaning. The heavy ash cakes were caused by the humidification system, but it was not possible to determine if the problem was caused by operation at a 30°F approach temperature or a short-excursion to a lower approach temperature caused by a rapid decrease in boiler load.

Sodium-Based Injection

Sodium-based reagents are much more reactive than calcium-based sorbents and can achieve significantly higher SO_2 removals during dry injection.[14,15] Figure 8 shows the SO_2 removal for dry sorbent injection for sodium bicarbonate and sodium sesquicarbonate. In Figure 8, SO_2 removals are plotted as a function of Normalized Stoichiometric Ratio (NSR). This corresponds to the amount of sodium compound injected relative to the amount of sodium required to form sodium sulfate, Na_2SO_4 (i.e., two moles of Na per mole SO_2). Sodium bicarbonate provided the highest SO_2 removal and was also the most efficient reagent in terms of sodium utilization. Flue gas temperature at the fabric filter inlet duct at Arapahoe Unit 4 varies from 250 to 280°F. The dry sorbent injection (DSI) system was originally designed for duct injection before the fabric filter only. However, initial testing with sodium bicarbonate showed that SO_2 removal was erratic, which was attributed to the low flue gas temperatures. The DSI system was modified to inject sodium sorbents at the air heater inlet where the flue gas temperature is approximately

600°F. It should be noted that sodium sesquicarbonate does not exhibit this slow reaction rate when injected ahead of the fabric filter.

A major disadvantage of sodium-based injection is that it converts some existing NO in the flue gas to NO_2. In addition, during the conversion process a small amount of the total NO_x, 5 to 15%, is removed. However, the net NO_2 exiting the stack is increased. While NO is a colorless gas, small quantities of the brown/orange NO_2 can cause a visible plume to develop. The chemistry of the conversion is not well understood but it is generally accepted that NO_2 increases as SO_2 removal increases. Figure 8 shows that NO_2 emissions are generally higher with sodium bicarbonate, although a significant amount of data scatter exists. The threshold NO_2 level that forms a visible plume is site specific; at Arapahoe Unit 4, a visible plume appears when NO_2 concentrations reach 30 to 35 ppm. Also, the NO_2 levels were found to depend on conditions in the fabric filter with NO_2 levels increasing dramatically after each cleaning cycle.[11]

SNCR Lance Performance Results

The recent test work has focused on the performance of the SNCR lances, both the NOELL ARIL lances and a comparison of the performance of the alternate DPSC lance to the ARIL lance.

<u>ARIL Lances</u>

Prior to incorporating the ARIL lances into the SNCR control system, a series of parametric tests was conducted to define the optimum injection angle at each load. As shown in Figure 4, each lance can rotate to inject urea into a different region of the furnace in order to follow the SNCR temperature window as the boiler load changes. The minimum injection angle is 22° (0° corresponds to injection vertically downward), at which point the chemical is injected parallel to the tube wall located below the lances. Smaller injection angles are not used to avoid direct liquid impingement on these tubes. An injection angle of 90° corresponds to injection straight across the furnace toward the front wall, and an angle greater than 90° results in injection of the solution in a direction up toward the roof-mounted burners.

While the primary focus of the parametric tests was to define the injection angle versus load, the tests also investigated the effects of:

- coal mill out-of-service patterns
- coal mill biasing
- biasing the urea flow along the length of the lances
- independent adjustment of the injection angles for each lance

The results of these tests are described below.

Effect of Lance Angle

One of the primary attributes of the ARIL lance system is the inherent flexibility of accessing the optimum flue gas temperature location by simply rotating the lance. Figure 9 shows the effect of varying the lance injection angle at loads of 43 and 50 MWe. All of the tests shown in these figures were performed at a N/NO_x ratio of 1.0, with two mills in service. At 43 MWe, varying the injection angle had little effect on NO_x removal, and the maximum removal occurred at an angle of 35 degrees (Figure 9a). However, Figure 9a shows that the lance angle had a large effect on NH_3 slip; decreasing from 46 ppm at an angle of 22° to under 5 ppm at an angle of 135°. This overall behavior at 43 MWe suggests that, on average, injection is occurring just on the high side of the SNCR temperature window. In fact, the optimum temperature, in terms of NO_x removal, appears to correspond to an angle of 35°. However, since it is desirable to maintain the NH_3 slip less than 10 ppm, an injection angle of 90° is a more appropriate operating angle at this load.

At a slightly higher load of 50 MWe (Figure 9b), the effect of lance injection angle was markedly different. At this load, where the average flue gas temperatures were higher, injection angle had little effect on NH_3 slip. However, at the higher temperature, lance angle had a large effect on NO_x removal. The relative insensitivity of the NH_3 slip and large sensitivity of the NO_x removal to lance angle suggests that at 50 MWe, chemical injection is occurring far on the high side of the SNCR temperature window for injection angles ranging from 22º to 135°.

The results at 43 and 50 MWe shown in Figure 9 illustrate how varying lance angle can be used to optimize the SNCR performance over the load range. As the load increases, the preferred injection angle will decrease. Again, the minimum angle is 22°, where the chemical is injected parallel to the tube sheet located below the lances.

Performance over the Load Range

The SNCR performance using the ARIL lances over the load range from 43 to 80 MWe is shown in Figure 10. Note that for this particular lance location, the flue gas temperatures are too high for the lances to be effective at loads greater than 80 MWe. As the load increases, the preferred lance angle decreases in order to inject the urea into a lower temperature region.

As discussed above, at 43 MWe with an angle of 90°, injection occurred on average just on the high temperature side of the window. At $N/NO_x = 1$, NO_x removals were 35% with less than 10 ppm NH_3 slip. At 50 MWe, a 45° injection angle was on average at a better location in the SNCR window, with NO_x removals of 40% and NH_3 slip less of 5 ppm at $N/NO_x = 1$. As the load increased to 60 MWe, a decrease in lance angle to 34° resulted in SNCR performance similar to a load of 43 MWe. At higher loads of 70 and 80 MWe, injection was clearly occurring on the high side of the temperature window. Note that the NH_3 slip at 80 MWe was higher than the slip at 70 MWe even though the chemical was injected into a region of higher overall temperature (i.e., compare the NO_x removals at 70 and 80 MWe in Figure 10). This effect was a result of temperature stratification in the furnace, and the way in which the stratification varies with different coal mill patterns. This effect is discussed in more detail below. However, comparing Figures 9 and 10 to the low load performance of the wall injectors in Figure 7 clearly shows that the lances have markedly improved the low-load performance of the SNCR system.

Effect of Boiler Operation on SNCR Performance

As mentioned above, local changes in temperature due to variations in boiler operating parameters (excess O_2, mill pattern, mill biases, etc.) can have a major impact on SNCR performance. This is particularly true at Arapahoe Unit 4 where the 12 burners are located on the roof of the furnace. Each of the four coal mills feeds three burners, two burners on one side of the furnace and a single burner on the other side of the furnace. Since the furnace has a division wall, there is an imbalance in heat release across the furnace, and a corresponding variation in flue gas temperature, when only three mills are in service. These temperature variations impact the performance of both the wall injectors and the ARIL lances. In this paper, the effect will be illustrated by looking at the performance of the ARIL lances with varying mill out-of-service patterns. During normal operation, Arapahoe Unit 4 operates with four mills in service over the load range from 80 to 110 MWe (although the unit can operate up to 100 MWe with only 3 mills). From 60 to 80 MWe, the unit typically operates with three mills in service. Below 60 MWe, the unit is usually operated with only two mills in service.

Figure 11 shows the effect of various mill out-of-service (OOS) patterns on east/west imbalances across the furnace. The bottom of Figure 11 shows a plan view of the in-service burners (numbered) and out-of-service burners (filled circles) for a given mill pattern. Note that the left side of these figures corresponds to the west wall of the furnace (adjacent to burners 1, 2 and 3), and the right side corresponds to the east wall (adjacent to burners 10, 11 and 12). With either A mill or C mill out-of-service, more heat release occurs on the east side of the furnace, while the west side has more heat release with either B mill or D mill out-of-service.

The change in lance metal temperatures provides a general indication of changes in flue gas temperatures on the east and west sides of the furnace. As seen in Figure 11, the changes in lance metal temperatures reflect the variations in heat release in the furnace with differing mill out-of-service patterns. Correspondingly, the NO_x removals and NH_3 slip levels also reflect these variations in temperature. For instance, NH_3 slip decreased on the west side when D mill was out-of-service, since more coal was fired (and the flue gas temperatures were higher) on the west side. The lance metal temperatures also indicated that, in general, the east side of the furnace was hotter than the west side. Figure 12 shows the overall impact of various mill out-of-service patterns on SNCR performance at 60 MWe. As can be seen, NO_x removals varied from 30% to 52% (@ $N/NO_x = 1.5$) depending on which particular mill was out-of-service. Comparably, the NH_3 slip varied from under 5 ppm to over 30 ppm with different mill-in-service patterns. This behavior made overall optimization of the SNCR system quite challenging.

In addition to the temperature variations that occur with the various mill out-of-service patterns, day-to-day variations can occur as a result of changes in the performance of the individual mills, or changes in any other variables which affect the flue gas temperature distribution. Three operational changes were investigated to deal with these types of temperature variations.

- varying the urea flow along the length of each lance
- independently varying each lance angle
- biasing the in-service coal mills

Varying the urea flow between the two liquid zones in each lance provided minor improvements in the performance of the SNCR system. Independently varying the lance angles as a function of the mill-in-service pattern also provided minor improvements. Unfortunately the implementation of either of these strategies would significantly complicate the automatic control system. On the other hand, biasing the in-service coal mills, which is relatively easy to implement, resulted in major improvements in the performance of the SNCR system. Arapahoe Unit 4 is equipped with four O_2 monitors at the economizer exit. Biasing the coal mills to provide a balanced O_2 distribution at this location is a fairly simple exercise for the boiler control operator. Figure 13 shows the improvements in SNCR performance that can be achieved by biasing the coal mills. These tests were performed at a load of 60 MWe with both lances at an injection angle of 22° and A mill out-of-service. The "biased" condition in Figure 13 corresponds to a negative 10% bias on B mill and D mill, and a positive 10% bias on C mill. This has the net effect of moving coal from the east side to the west side of the furnace to compensate for A mill being out-of-service (see bottom of Figure 11). Biasing the mills increased NO_x removals from nominally 27% to 42% at an NH_3 slip limit of 10 ppm.

Overall System Performance

The parametric tests were conducted to determine at which loads the ARIL lances should be used, as well as the optimum injection angle for each of these loads. Based on the parametric tests, the control system has been set up to operate with the Level 1 wall injectors at loads above 80 MWe. Below 80 MWe, the ARIL lances are used. Figure 14 compares the NO_x removal over the load range for injection at the two locations with an NH_3 slip limit of 10 ppm. It is evident that the installation of the ARIL lances has improved low-load performance of the SNCR system. Currently, NO_x removals of more than 30% are achievable over the load range with less than 10 ppm NH_3 slip. The minimum NO_x removal of 30% occurs at 80 MWe, which corresponds to the point where the temperature becomes too high for the ARIL lances and too low for the Level 1 injectors. With continuing operation of the system, it is anticipated that further optimization will take place as the operators gain more experience balancing the furnace.

Alternate Lance Design

While the NO_x removal performance of the ARIL lances has been good, their location in the furnace has resulted in some operational problems. At this particular location in the furnace, the lances are exposed to a large differential heating between the top and bottom surfaces. The top surface receives a high radiant load from the burners, while the bottom of the lance radiantly communicates with the relatively cold tube wall immediately below. This uneven heating pattern causes a great amount of thermal expansion along the upper surface, and the lances bend downward toward the tubes. Within 30 minutes of insertion, the tip of each lance would drop by approximately 12 to 18 inches. Within less than six weeks of operation, the lances became permanently bent, making insertion and retraction difficult. This was partially addressed by adding additional cooling slots at the end of the lance.

An alternate lance design supplied by Diamond Power Specialty Company (DPSC) was evaluated during this test period. As mentioned previously, this design sprays the urea solution through a single atomizer at the entrance to the lance. This provides evaporative cooling to supplement the air cooling. The evaporative cooling was expected to help minimize the lance bending discussed above. This alternate lance design was evaluated by installing a single lance on the west side of the boiler in place of one of NOELL's ARIL lances. The two different lance designs were compared during a nominal three week test program.

Overall, the DPSC lance performed mechanically well. The lance exhibited less bending than the ARIL lance, and eliminated air injection on the outside of the boiler.

Figure 15 compares the performance of the ARIL and DPSC lances on the west side of the furnace. In terms of NO_x reduction and NH_3 slip performance, the DPSC lance was not quite as good as the ARIL lance. With the B mill OOS, the ARIL lance yielded 42 percent NO_x removal with less than 5 ppm slip on the west side (60 MWe, N/NO_x = 1). Under comparable conditions, the DPSC lance yielded 36 percent NO_x removal and less than 5 ppm slip. This slight difference in performance is primarily attributable to the urea distribution along the lance. The ARIL lance uses a separate liquid circuit with individual liquid orifices at each air nozzle. This results in a fairly uniform liquid distribution along the length of the lance. The DPSC lance, on the other hand, sprays the urea solution into the cooling air stream at the inlet to the lance. Impingement on the walls and incomplete evaporation results in the liquid tending to be carried toward the far end of the lance, with part of the urea exiting as a stream of liquid rather than a finely atomized spray. In fact, this explains why the optimum angle for the DPSC lance is 34° compared to 22° for the ARIL lance at 60 MWe. The higher temperature associated with the 34° angle is needed to evaporate the liquid stream. In addition, the feed tube geometry of the DPSC lance created an additional pressure drop, restricting the amount of cooling air flow. This resulted in less penetration of the air jets, although this was partially compensated for by the unatomized portion of the urea solution, which carried the urea farther into the furnace before decomposing and releasing the reactive nitrogen components.

Overall, the results of the short test program of the DPSC lance were sufficiently positive that a second DPSC lance has been ordered. An additional three weeks of testing is planned.

Integrated System Performance

An important part of the test program was demonstrating the integrated performance of the various NO_x reduction and SO_2 removal technologies. In particular, a key element of the program was documenting the synergistic benefits of simultaneous operation of the SNCR and sodium-based dry sorbent injection system. When operated together, it was expected that the SNCR system would reduce NO_2 emissions from the sodium DSI system, while the sodium DSI system would in turn reduce NH_3 slip from the SNCR system.

Ideally, it would have been desirable to parametrically evaluate the merits of the integrated system over a range of operating conditions. This was not entirely possible for a number of reasons. With sodium-based dry sorbent injection, NO_2 levels are not only dependent on the amount of sodium injected, but also depend on the particulate in the fabric filter and the cleaning intervals.[11] Likewise, the time required for NH_3 levels to stabilize at the exit of the fabric filter, both before and after sodium injection, was greater than the 10-hour a day period during which the load from Arapahoe 4 could be blocked. Thus, characterizing the integrated performance relied on a limited number of parametric tests followed by a series of "long term" tests under normal load following conditions. During these "long-term" tests, the NO_x reduction and SO_2 removal systems were operated in automatic while the unit was operated according to system dispatch requirements.

Data were collected at regular intervals using a data logger. No effort was made to set up specific test conditions, as these tests were designed to simulate operation of these systems once they are turned over to the plant at the completion of this program.

The results of a parametric test with sodium sesquicarbonate injection and the SNCR system are shown in Figure 16. During these tests, the DSI system was started first, followed by the SNCR system. For this test, the DSI system was set at an NSR of 2.0 (i.e., 4 moles of sodium per mole of SO_2) and the SNCR system at $N/NO_x = 0.6$. Following the start of the DSI system, the SO_2 removal stabilizes at nominally 70% removal and the NO_x removal at 12%. This level of NO_x removal is consistent with previous tests of the DSI system. The NO_2 levels increased to only about three ppm at the point that the SNCR system was started. With the SNCR system started, the NO_x removal increased to 35 to 40% and the NO_2 levels remained constant at three ppm. Even following a cleaning cycle, the NO_2 levels did not increase with the SNCR system in operation. Just before 1800 hours, the SNCR system was turned off and an immediate increase in NO_2 was noted.

Figure 17 shows the results of a parametric test with sodium bicarbonate injection ahead of the air preheater. With sodium bicarbonate injection alone at an NSR of 1.1, NO_2 levels on the order of 50 ppm are expected (see Figure 8). For the test results shown in Figure 16, the SNCR system was started at N/NO = 1.1 nominally two hours before the DSI system. As can be seen, the NO_2 levels remained near zero for the entire test. Further, it can be seen that following the start of the DSI system, the NH_3 slip levels continued to decrease.

The results shown in Figures 16 and 17 clearly show that there is a synergistic benefit of operating the SNCR and sodium-based DSI systems simultaneously.

Because of the difficulties encountered running these short term integrated tests, the balance of the integrated tests were run under normal load following conditions. During these tests the integrated system was operated 24 hours per day. Figure 18 shows the data collected during one 24-hour period (February 25, 1996). During these tests, the integrated system was utilizing sodium sesquicarbonate injection ahead of the fabric filter, and the SNCR system was load following with both the wall injectors and ARIL lances.

On this day, the boiler load was nearly constant for the first 17 hours of the day. The N/NO_x ratio and NH_3 emissions were also relatively steady during this time. At 1600 hours, the DSI system was started with a 75 percent SO_2 removal setpoint with the hope that the load would remain steady and it would be possible to assess the beneficial effects of running the integrated system. Although, the load increased significantly about two hours after the DSI system was started, it eventually settled back down to a level similar to the level before the increase. Figure 18 shows that the average NH_3 emissions with and without sodium injection were similar, which was expected since the NH_3 trim control was functioning during both of these tests. However, the results also show that there was a substantial increase in the N/NO_x ratio. Since the SNCR control system was set to maintain the NH_3 emissions within the range of 7 to 8 ppm, it should have increased the urea injection rate if the DSI system reduced NH_3 emissions. A temporary increase was expected as a result of the load swing, but the N/NO_x ratio should have returned to the pre-swing level within two to three hours (as was seen after the “morning demand peak” between 0800 and 0900 hours). When the DSI system was started at 1600 hours, there was an immediate 10 percent increase in the NO_x removal, which is consistent with the increases seen during sodium-based DSI-only tests. After this initial NO_x removal increase, there was another slower increase (amounting to nominally 10 to 15 percent removal) which occurred as the N/NO_x ratio increased. Although the scaling of the data makes it difficult to see, Figure 18 indicates that the N/NO_x ratio basically doubled after the DSI system was started. The increase in N_2O emissions (from nominally 8 to 16 ppm), confirms that the N/NO_x ratio was increased by roughly a factor of two. These results clearly indicate that there was a substantial reduction in the stack NH_3 slip, when the SNCR and DSI systems were run concurrently.

Figure 19 shows data collected during the 24-hour period on March 4, 1996. The DSI system was operated for the entire period and the SNCR system was started at 1420 hours. The boiler load was fairly steady at this time, and was low enough for the control system to insert the ARIL lances. Although the DSI feedrate was not very consistent, Figure 18 shows that there was nominally a 50 percent reduction in the NO_2 emissions when urea injection began. The load remained steady for nearly four hours; then it increased for the usual "evening demand peak" at 1800 hours. When the lances retracted, the N/NO_x ratio dropped as demanded by the control system, and the NO_2 emissions were also seen to decrease. By 1900 hours, the NO_2 emissions had been reduced to near-zero levels. This effect is due to the difference in the NH_3 emissions between injection at the Level 1 and ARIL locations. Although effort was made to set up the SNCR control system such that the NH_3 slip was limited to 10 ppm throughout the load range, the Level 1 location is "cooler" overall than the ARIL location; thus injection at Level 1 is more sensitive to variations in the flue gas temperature profile. Therefore, in general, urea injection at the Level 1 location results in higher NH_3 slip levels at the fabric filter inlet. Since the NH_3 emissions are generally higher with urea injection at the Level 1 location, it would be expected that the reduction in stack NO_2 emissions would also be higher (relative to injection at the ARIL location). The hypothesis is further supported by the decrease in NO_2 emissions seen when the urea injection switched from the lances to Level 1 at 1800 hours in Figure 19, but also by the increase in NO_2 seen when the lances were reinserted at 2000 hours. When the lances went in at this time, the NO_2 emissions were essentially zero. After an hour, however, the NO_2 emissions slowly began to increase, finally leveling out at approximately 8 ppm.

The above (Figures 16 through 19) demonstrate the synergistic benefits of the integrated process. The NH_3 slip from the SNCR process suppresses the NO_2 emissions associated with NO to NO_2 oxidation by dry sodium injection. Concurrently, the sodium reduces the NH_3 slip from the SNCR process. (Note: In the present case, the control system adjusts the urea injection rate to maintain a set NH_3 slip level, and the tendency to reduce NH_3 slip is manifested in a higher N/NO_x ratio for a given NH_3 slip.)

Ammonia Absorption on the Fly Ash

An issue that needs to be addressed with any post-combustion NO_x reduction technology with NH_3 slip is the absorption of ammonia on the fly ash. This can have a number of impacts ranging from personnel safety while handling the ash, odor problems, or impacting the salability of the ash for future use as a cement aggregate. In the latter, a salable product becomes a disposal problem with an attached economic penalty. At the Arapahoe Station, the ash is not sold for use in cement. Thus, the only problems that have been encountered have been an occasional NH_3 odor around the ash handling area and potential concern with worker safety should the concentrations become too high.

At Arapahoe Unit 4, ash is removed from the fabric filter hoppers with a vacuum system and transported dry to an ash silo. When loaded onto trucks for transport to the disposal site, the ash is wetted with about 20% water (by weight) in order to minimize fugitive dust emissions. Depending upon the specific ash characteristics, this wetting process can result in the release of NH_3 vapors from the ash. Whether or not NH_3 is released from the ash depends primarily on the pH of the aqueous phase on the surface of the ash particles. As the pH increases above a level of 9 to 9.5, there is an increased release of vapor-phase ammonia.

During the test program with urea injection alone, the ammonia concentration in the ash varied over the range of 100 to 200 ppm (measured on a weight basis). The ash ammonia content appeared to be primarily related to the NH_3 slip levels from the SNCR system and, to some extent, the fabric filter cleaning cycles. During long-term testing with the SNCR system alone, and a 10 ppm NH_3 slip limit at the stack, there were no incidents of excessive NH_3 odors during the ash handling process.

Testing has shown that when the SNCR system is operated in conjunction with the dry sodium injection system, the urea injection rate could be increased substantially while maintaining a 10 ppm NH_3 slip level at the stack. This is one of the synergistic benefits of the patented Integrated Dry NO_x/SO_2 Emissions Control System discussed above. However, during these tests, the ammonia concentration in the ash increased to the range of 400 to 700 ppm (weight basis), and there were frequent occurrences of NH_3 odors at the ash silo. Reducing the NH_3 slip set point to the range of 4 to 5 ppm reduced the ammonia concentration of the fly ash down to the 100 to 200 ppm range (weight basis), but the odor problem persisted.

At first, it was thought that the odor problem was a result of the sodium changing the pH of the ash. The pH resulting from placing 0.5 gram of ash in 200 ml of distilled water was 9.3 for an ash sample without sodium injection. The same test run with an ash sample from a test with sodium injection resulted in a pH of 10.3. While the sodium did indeed increase the pH, which in turn would tend to release more NH_3 from the aqueous to the vapor phases, the pH difference did not appear significant enough to account for the ash handling problems encountered.

An interesting observation was made during the pH measurements. While the presence of sodium was found to slightly increase the final pH, it was also found to have a large effect on the rate at which the pH changed as the ash was wetted. Figure 20 shows the change in pH versus time after 0.5 gram of ash is placed into 200 ml of distilled water and stirred. With the coal ash alone, almost 30 minutes are required for the soluble components of the ash to dissolve and change the pH to a final value of 9.3. However, with sodium present in the ash sample, the pH develops almost instantaneously, presumably because of the higher solubility of the sodium compounds in the ash. This more rapid development of the high pH level can result in more rapid and localized release of the ammonia vapor, and may explain the odor problem encountered when concurrently operating the SNCR and sodium systems. Other than decreasing the level of NH_3 slip from the SNCR system, additional approaches to dealing with this issue have not been explored.

CONCLUSIONS

Public Service Company of Colorado, in cooperation with the U.S. Department of Energy and the Electric Power Research Institute, has installed the Integrated Dry NO_x/SO_2 Emissions Control System. The system has been in operation for over three years and preliminary conclusions are as follows:

- NO_x reduction during baseload operation of the unit with low-NO_x burners and overfire air ranges from 63 to 69% with no increase in unburned fly ash carbon or CO emissions.

- With the addition of retractable lances to the SNCR system, improved low load performance of the system urea-based SNCR injection allows an additional 30 to 52% NO_x removal with an ammonia slip limit of 10 ppm at the fabric filter inlet. This increases total system NO_x reduction to greater than 80% at full load, significantly exceeding the project goal of 70%.

- The ability to follow the temperature window by rotating the ARIL lances has been demonstrated and also proved to be an important feature in optimizing the performance of the SNCR system.

- SO_2 removal with calcium-based dry sorbent injection into the boiler at approximately 1000°F flue gas temperature was disappointing with less than 10% removal achieved.

- SO_2 removal with calcium-based dry sorbent injection into the fabric filter duct has been less than expected with a maximum short term removal rate approaching 40%.

- Sodium bicarbonate injection before the air heater has been very effective with short term SO_2 removals of over 80% possible. Longer term testing has demonstrated removal near 70% at an approximate NSR of 1.0.

- Sodium sesquicarbonate injection ahead of the fabric filter can achieve 70% removal on a long term basis, at an approximate NSR of 2.0.

- NO_2 emissions are generally higher when using sodium bicarbonate than when using sodium sesquicarbonate. The NO_2 generated during sodium-based injection is related to SO_2 removal and the cleaning cycle of the fabric filter, but all factors important to NO_2 generation are not fully understood.[11]

- Long term testing of the integrated system demonstrated the synergistic benefit of operation with SNCR and sodium-based dry sorbent injection (i.e., reduce NO_2 and NH_3 emissions).

- When the SNCR and dry sodium systems were operated concurrently, an NH_3 odor problem was encountered in the area around the unit 4 ash silo. This problem appears to be related to the rapid change in pH due to the presence of sodium in the ash.

REFERENCES

1. G. Green and J. Doyle, *Integrated SO_x/NO_x Emission Control System (IS/NECS),* 1990 ASME International Joint Power Conference, (BR-1424).

2. T. Hunt and J. Doyle, *Integrated Dry NOx/SO2 Emission Control System Update*, First Annual Clean Coal Technology Conference, (September 22-24, 1992) Cleveland, OH.

3. T. Hunt and J. Doyle, *Integrated SO_x/NO_x Emissions Control System (IS/NECS)-Update,* International Power Generation Conference, (October 18-22, 1992) Atlanta, GA.

4. E. Mali et al., *Low-NO_x Combustion Modifications for Down-Fired Pulverized Coal Boilers*, American Power Conference, (April 13-15, 1993) Chicago, IL.

5. T. Hunt et al., *Low-NO_x Combustion Modifications for Top-Fired Boilers*, 1993 EPRI/EPA Joint Symposium on Stationary NO_x Control, (May 24-27, 1993) Miami Beach, FL.

6. T. Hunt et al., *Selective Non-Catalytic Operating Experience Using Both Urea and Ammonia*, 1993 EPRI/EPA Joint Symposium on Stationary NO_x Control, (May 24-27, 1993) Miami Beach, FL.

7. T. Hunt et al., *Preliminary Performance and Operating Results from the Integrated Dry NO_x/SO_2 Emissions Control System*, Second Annual Clean Coal Technology Conference, (September 6-9, 1993) Atlanta, GA.

8. R. Smith et al., *Operating Experience with the Integrated Dry NO_x/SO_2 Emissions Control System*, 207th ACS National Meeting, (March 13-17, 1994) San Diego, CA.

9. T. Hunt et al., *Current Progress with the Integrated Dry NO_x/SO_2 Emission Control System*, Third Annual Clean Coal Technology Conference, (September 1994) Chicago, IL.

10. T. Hunt et al., *NO_x Reduction on a Coal-Fired Utility Boiler with Low-NO_x Burners, Overfire Air, and SNCR*, Engineering Foundation Conference on Economic and Environmental Aspects of Coal Utilization VI, (January 29-February 2, 1995) Santa Barbara, CA.

11. T. Hunt et al., *Performance of the Integrated Dry NO_x/SO_2 Emissions Control System,* Fourth Annual Clean Coal Technology Conference, (September 1995) Denver, CO.

12. S.J. Bortz et al., *Dry Hydroxide Injection at Economizer Temperatures for Improved SO_2 Control*, 1986 Joint Symposium on Dry SO_2 and Simultaneous SO_2/NO_x Control Technologies, (June 2-6, 1986) Raleigh, North Carolina.

13. D.C. McCoy et al., *The Edgewater Coolside Process Demonstration a Topical Report,* DOE/PC/79798-T26, (1992).

14. L.J. Muzio et al., *Dry SO_2 Particulate Removal for Coal-Fired Boilers*, Volume 2: 22-MW Demonstration Using Nacholite, Trona, and Soda Ash, EPRI Report CS-2894, (June 1984).

15. M.R. Fuchs et al., *Full-Scale Demonstration of a Utility Dry Sodium Injection FGD Facility*, EPRI Final Report, Project RP-16826, (December 1989).

ACKNOWLEDGMENTS

The authors would like to thank Mr. Jim Love, Arapahoe Plant Manager, and his maintenance and operating staff for the exceptional cooperation they have provided throughout this project. The advice and technical assistance provided by Ms. Barbara Tool-O'Neil at EPRI have also been of great assistance throughout the project. Last, but definitely not least, is our appreciation to the many PSCC Engineering and Construction personnel and other contractors who have made the Integrated Dry NO_x/SO_2 Emissions Control System a success.

DISCLAIMER

This paper was prepared pursuant to a Cooperative Agreement partially funded by the U.S. Department of Energy, and neither Public Service Company of Colorado, any of its subcontractors, the U.S. Department of Energy, nor any person acting on behalf of either:

(a) Makes any warranty or representation, express or implied, with respect to the accuracy, completeness, or usefulness of the information contained in this paper, or that the use of any information, apparatus, method or process disclosed in this paper may not infringe privately-owned rights: or

(b) Assumes any liabilities with respect to the use of, or for damages resulting from the use of, any information, apparatus, method or process disclosed in this paper.

Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the U.S. Department of Energy. The views and opinions of authors expressed herein do not necessarily state or reflect those of the U.S. Department of Energy.

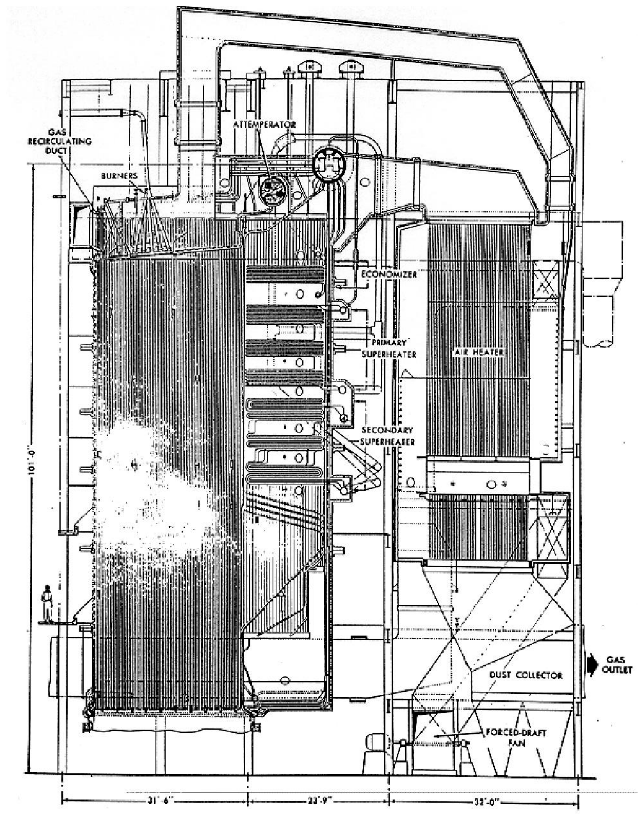


Figure 1. Boiler Elevation

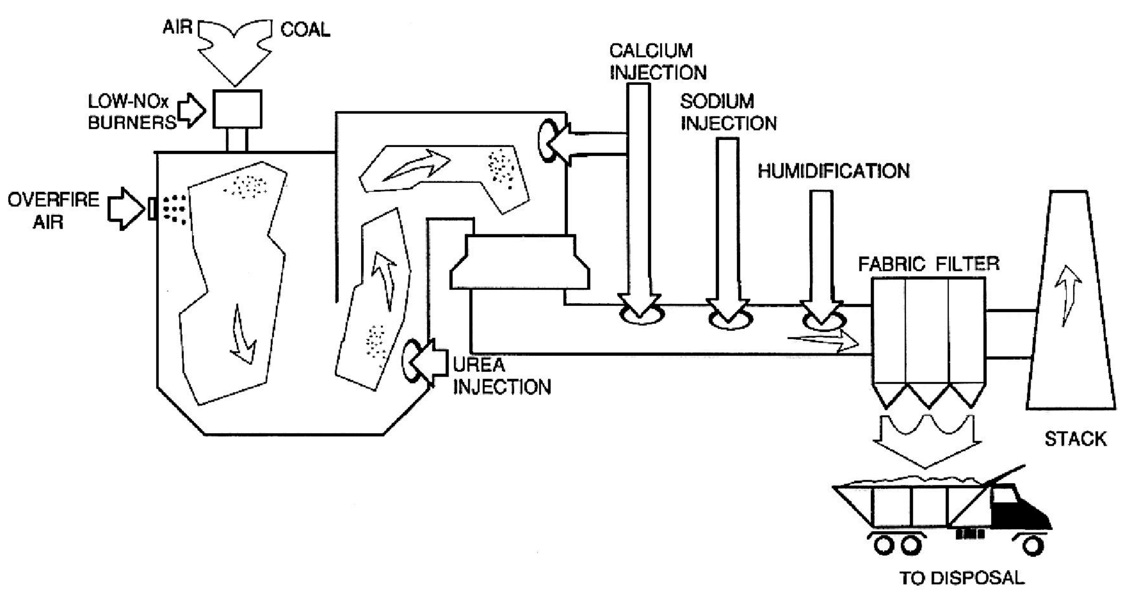


Figure 2. Process Flow Diagram of the Integrated NO_x/SO_2 Emission Control System

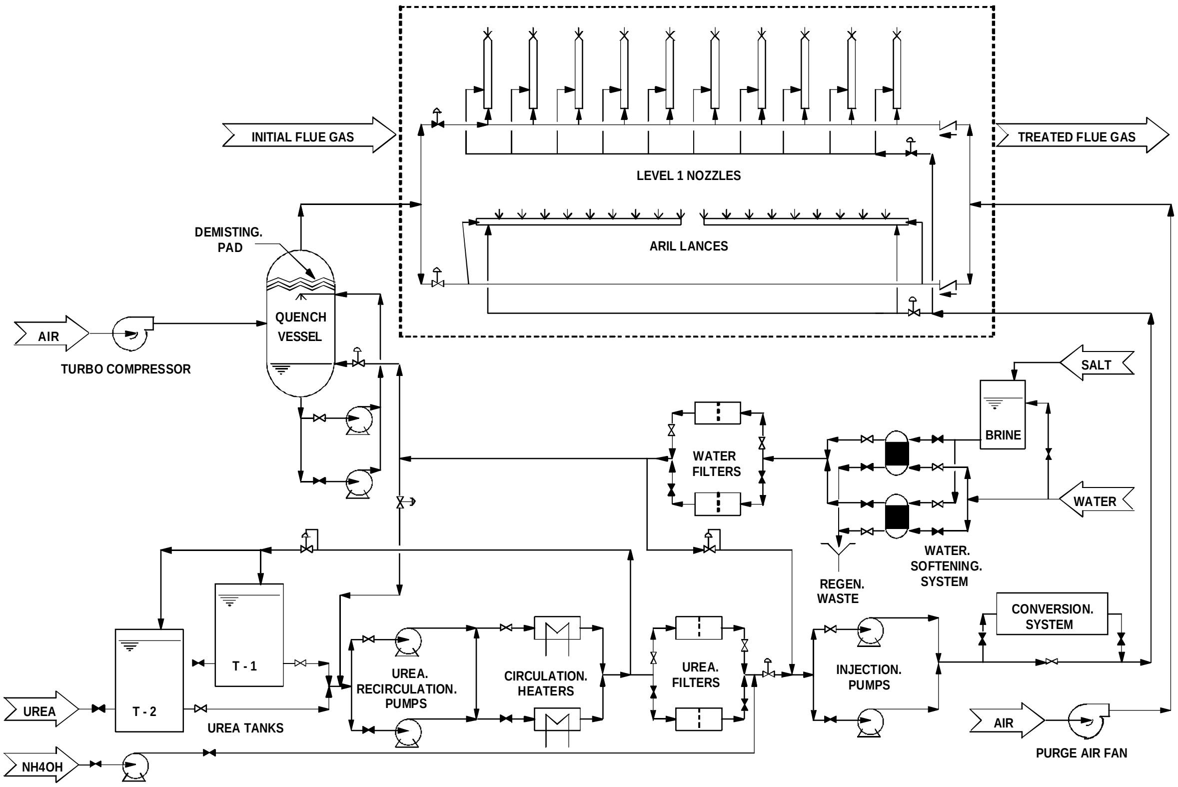


Figure 3. SNCR System Flow Diagram

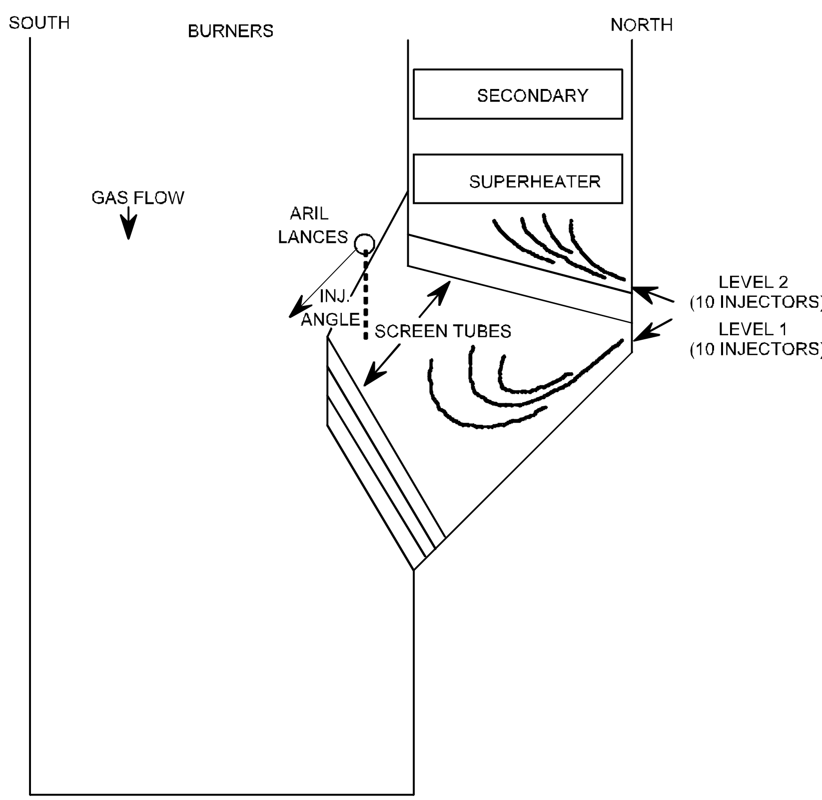


Figure 4. SNCR Injection Locations

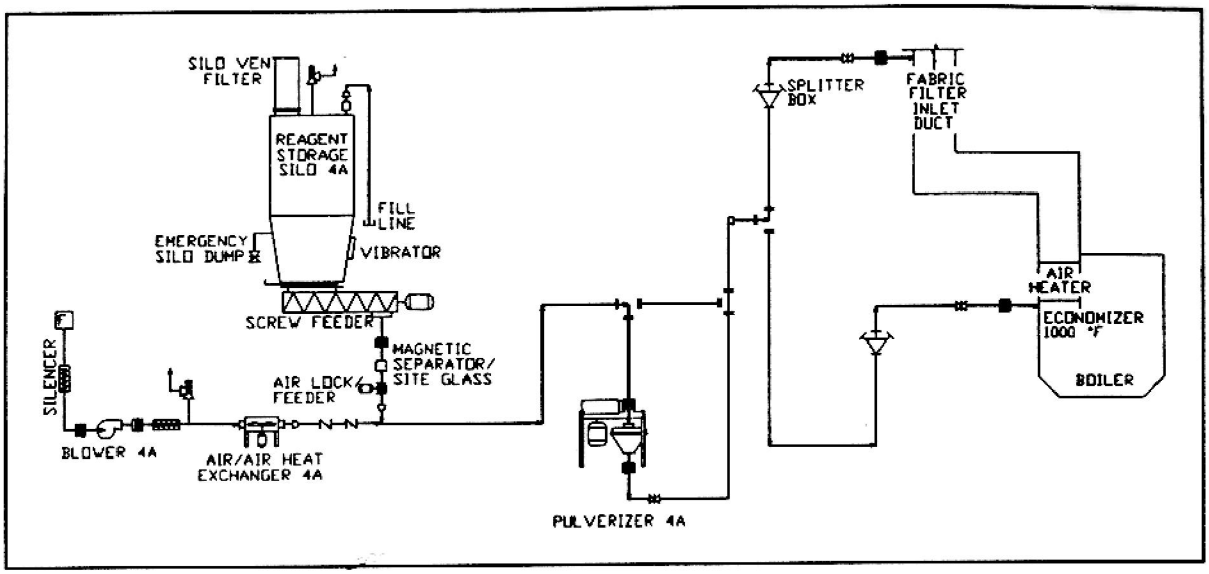


Figure 5. Dry Sorbent Injection Flow Diagram

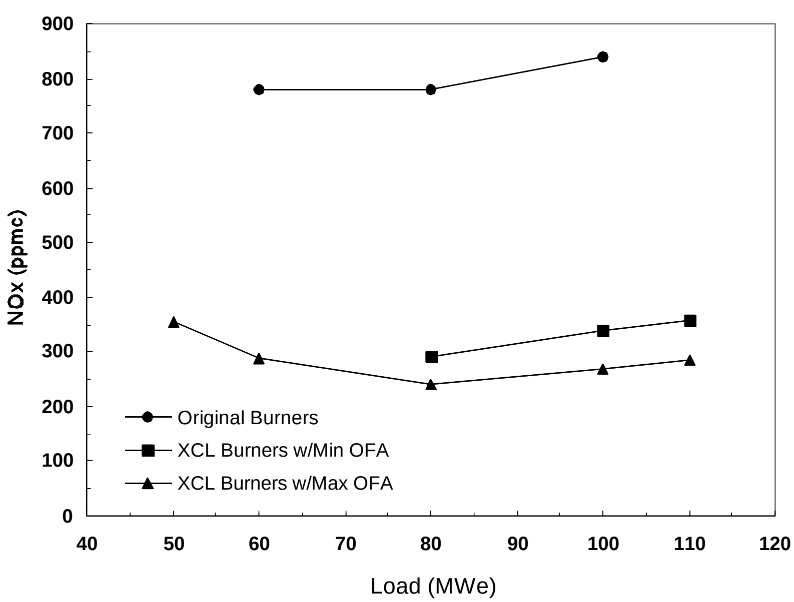


Figure 6. NO_x Emissions Before and After Low-NO_x Combustion System Retrofit

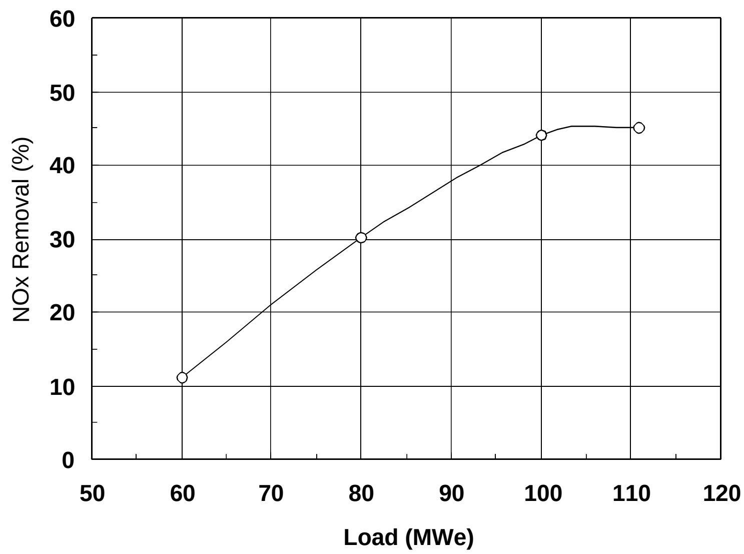


Figure 7. Performance of the Original SNCR System as a Function of Load
(10 ppm NH_3 slip limit)

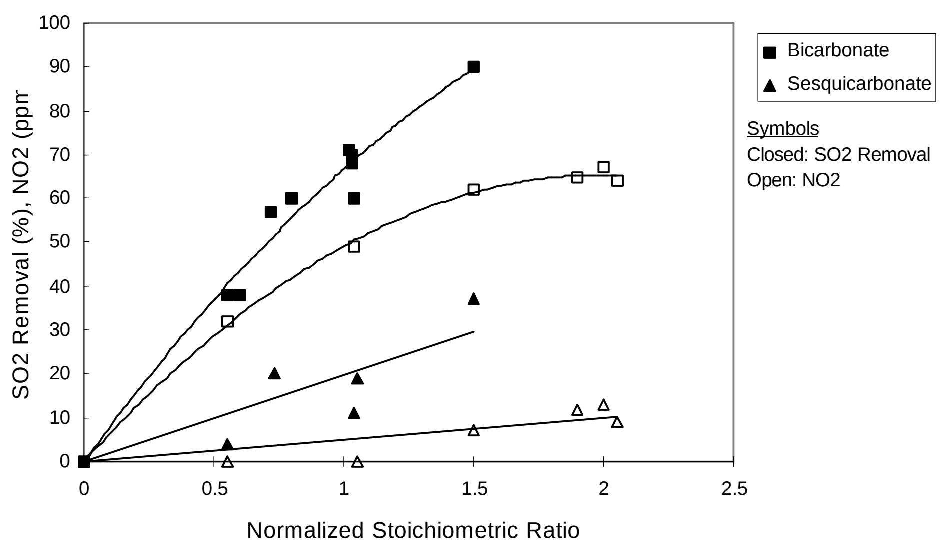
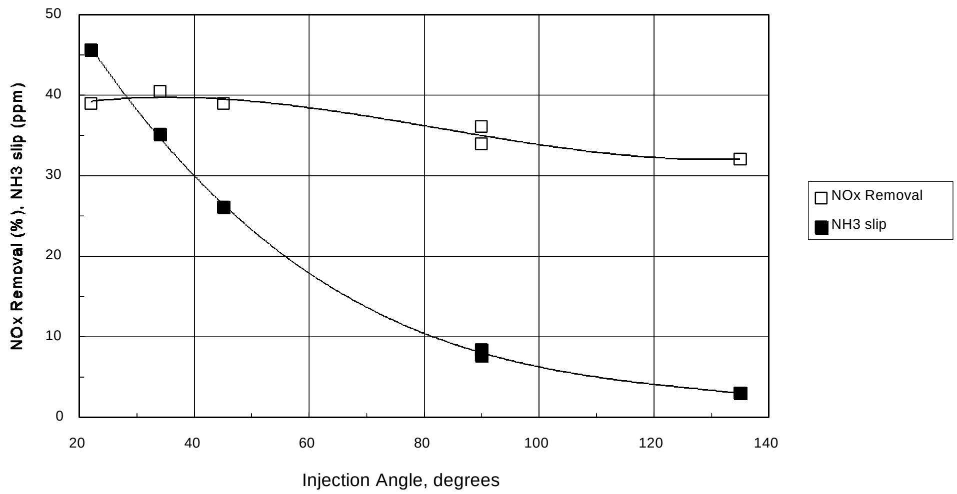
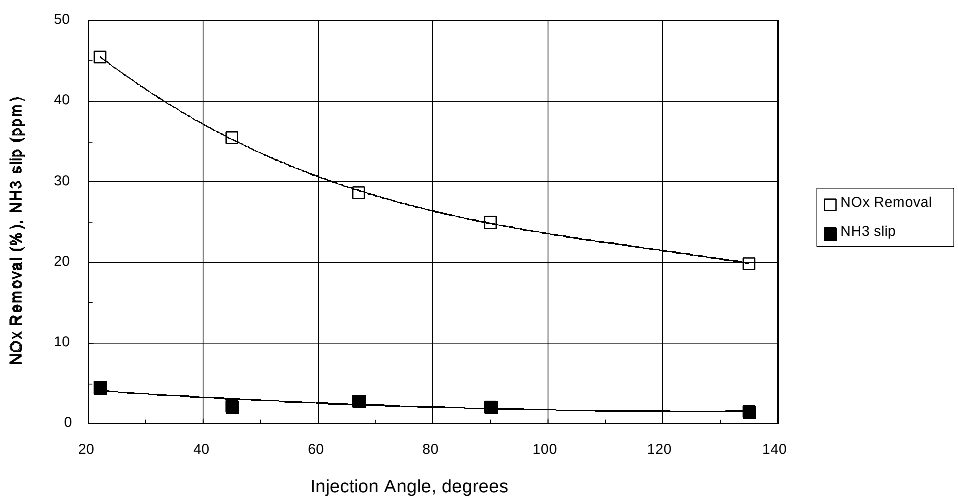


Figure 8. Performance of Sodium Dry Sorbent Injection
(sodium sesquicarbonate injected ahead of the fabric filter;
sodium bicarbonate injected ahead of the air preheater)

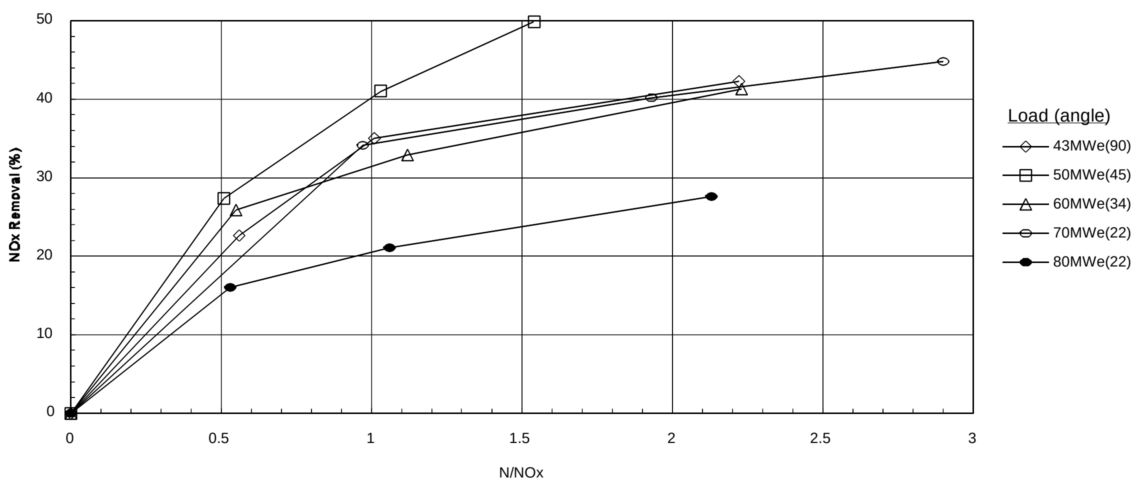


(a) 43 MWe

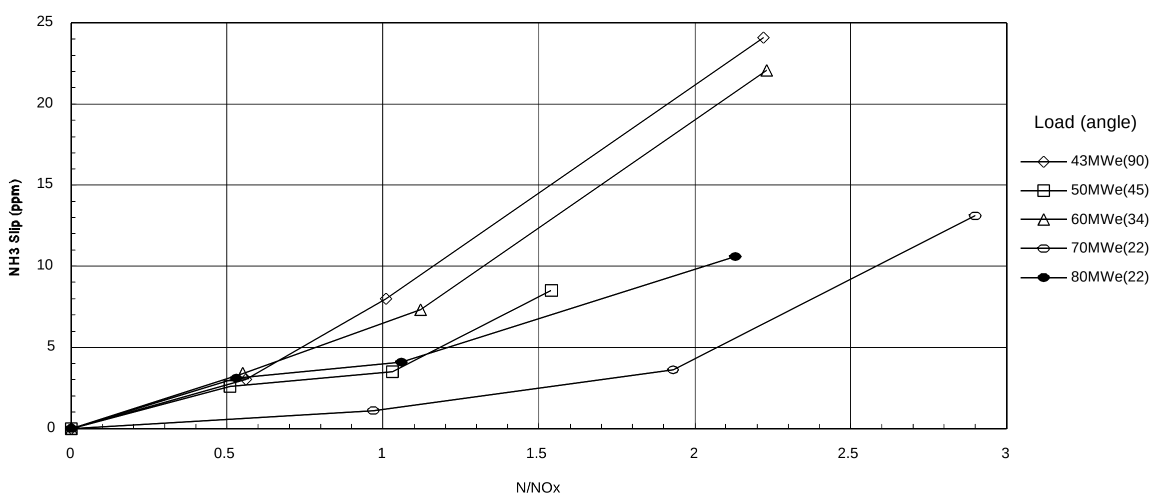


(b) 50 MWe

Figure 9. Effect of Injection Angle on NO_x Removal and NH_3 Slip
(Loads: 43 and 50 MWe, $N/NO_x = 1.0$)



(a) NOx Removal



(b) NH3 slip

Figure 10. ARIL Lance Performance Over the Load Range: 43 to 80 MWe

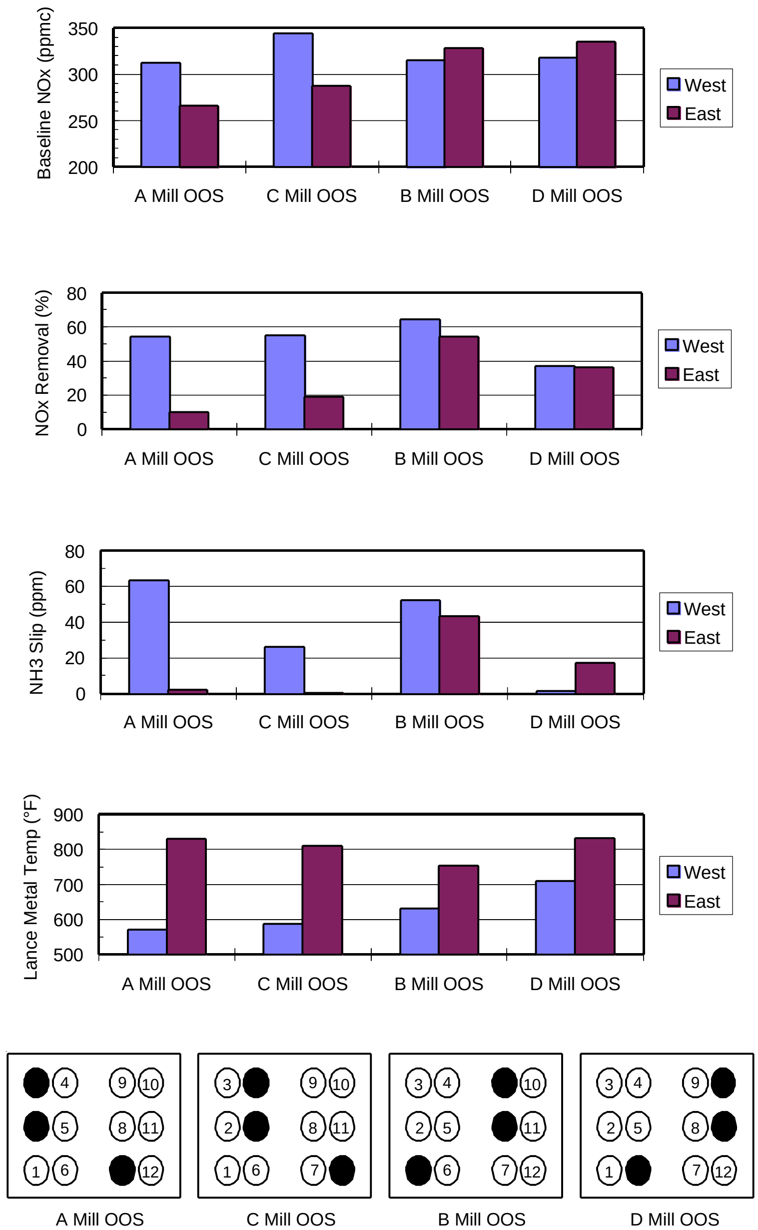


Figure 11. East-West Baseline NO_x Emissions, NO_x Removals, NH_3 Slip Levels and Lance Metal Temperature Distributions as a Function of Mill-in-Service Pattern at 60 MWe (N/NO_x = 2.0, 22° Injection Angle)

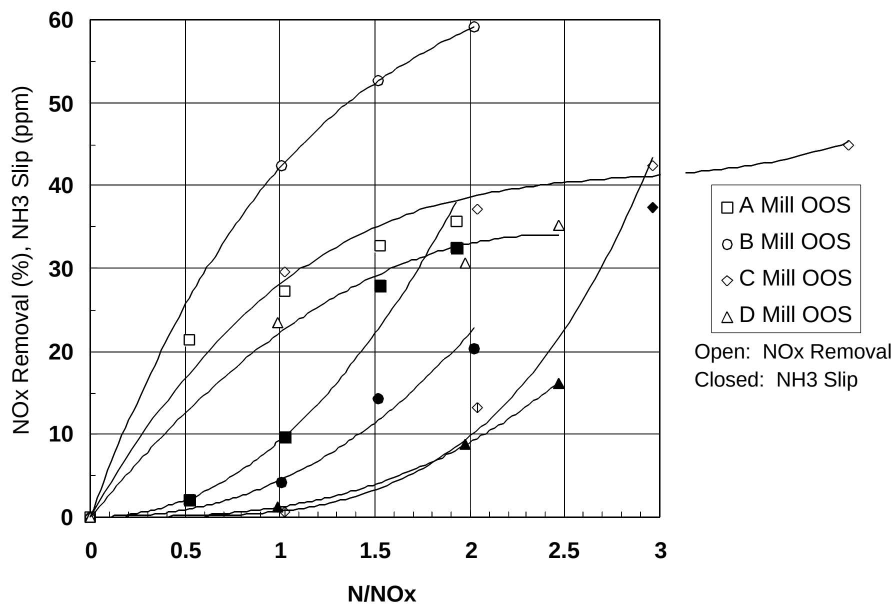


Figure 12. Effect of Mill-in-Service Pattern on
ARIL Lance Performance at 60 MWe (22° Injection Angle)

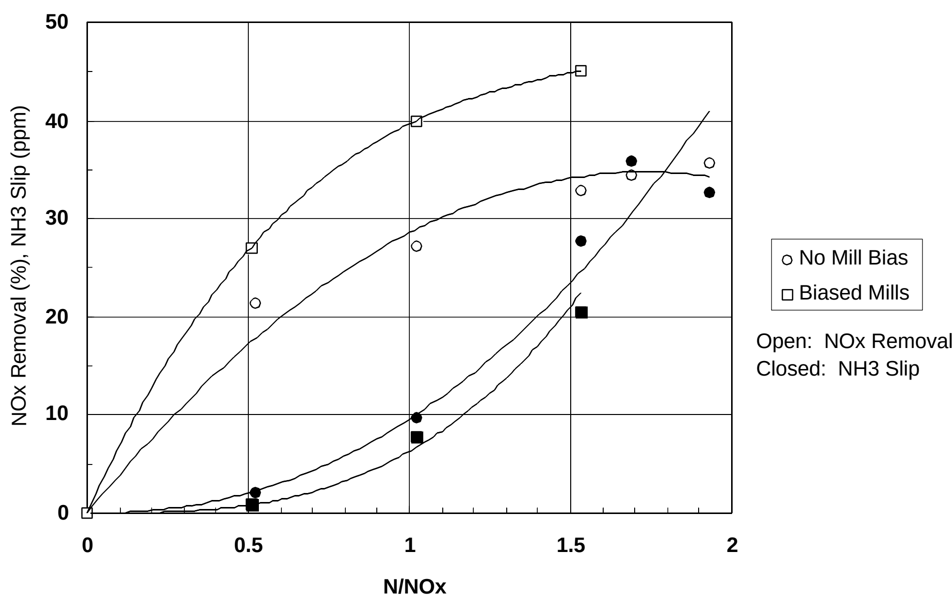


Figure 13. Effect of Coal Mill Bias on ARIL Lance Performance at 60 MWe
(A Mill OOS, 22° Injection Angle)

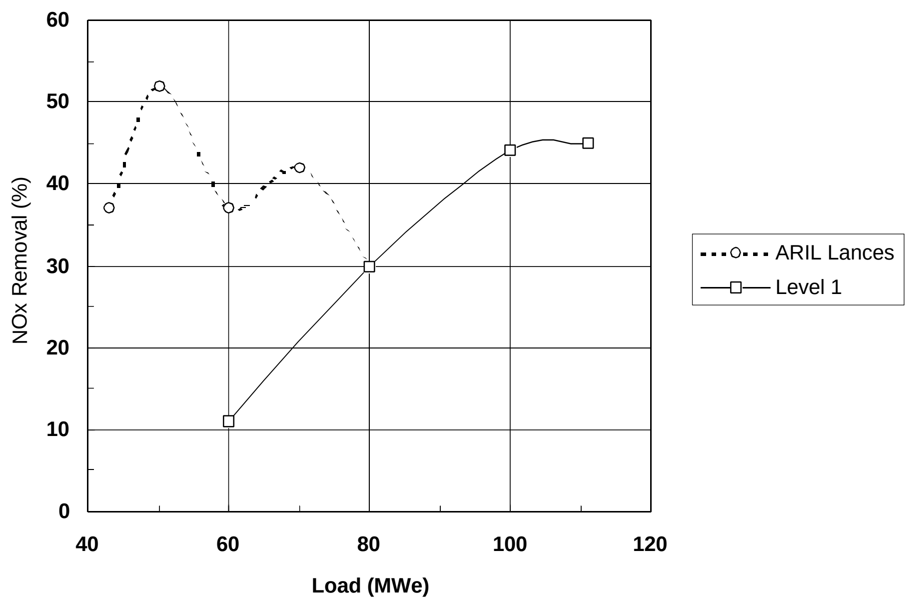


Figure 14. NO_x Removal as a Function of Load for an NH_3 Slip Limit of 10 ppm

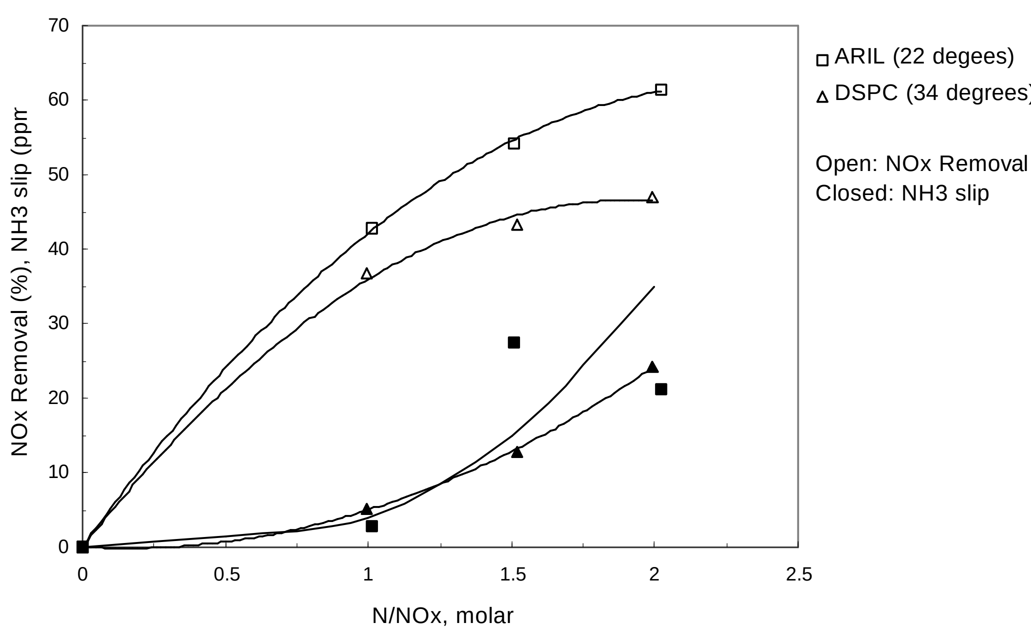


Figure 15. Comparison of the ARIL and DPSC Lance Performance

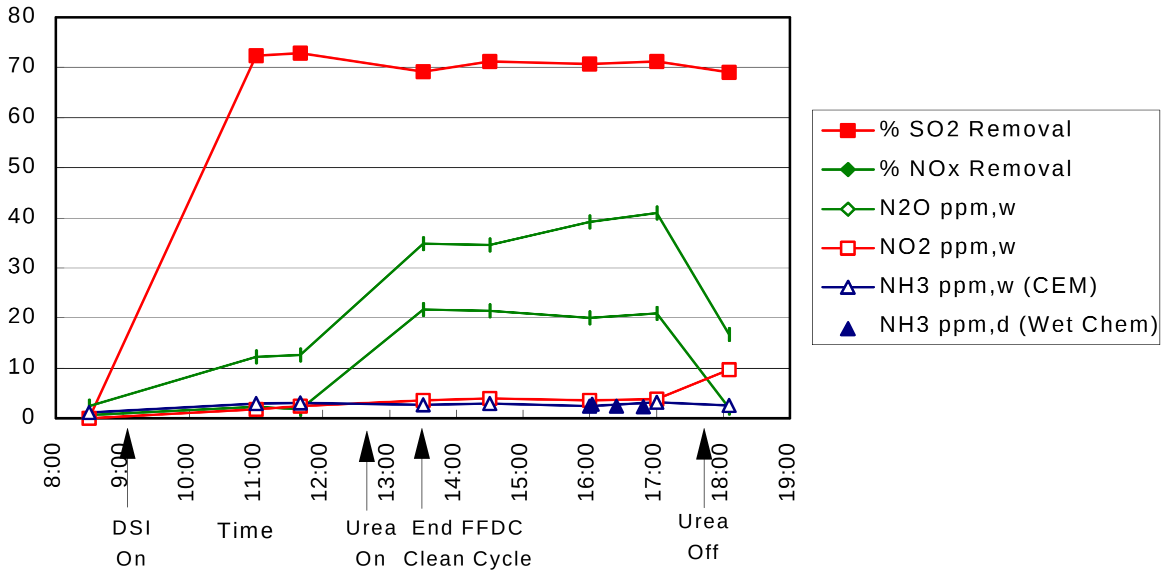


Figure 16. Time History of 100 MWe Integrated Test with Sodium Sesquicarbonate Injection (2Na/S = 2.0, N/NO_x = 0.6, A Mill OOS)

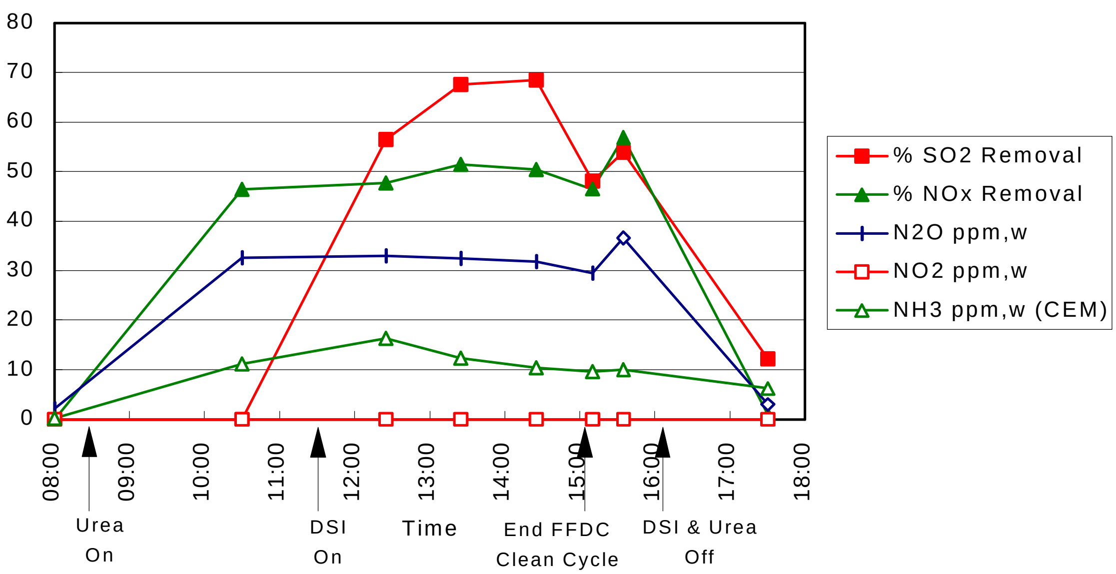


Figure 17. Time History of Integrated Test with Sodium Bicarbonate Injection (2Na/S = 1.1, N/NO_x = 1.1, 100 MWe, 4 Mills in Service)

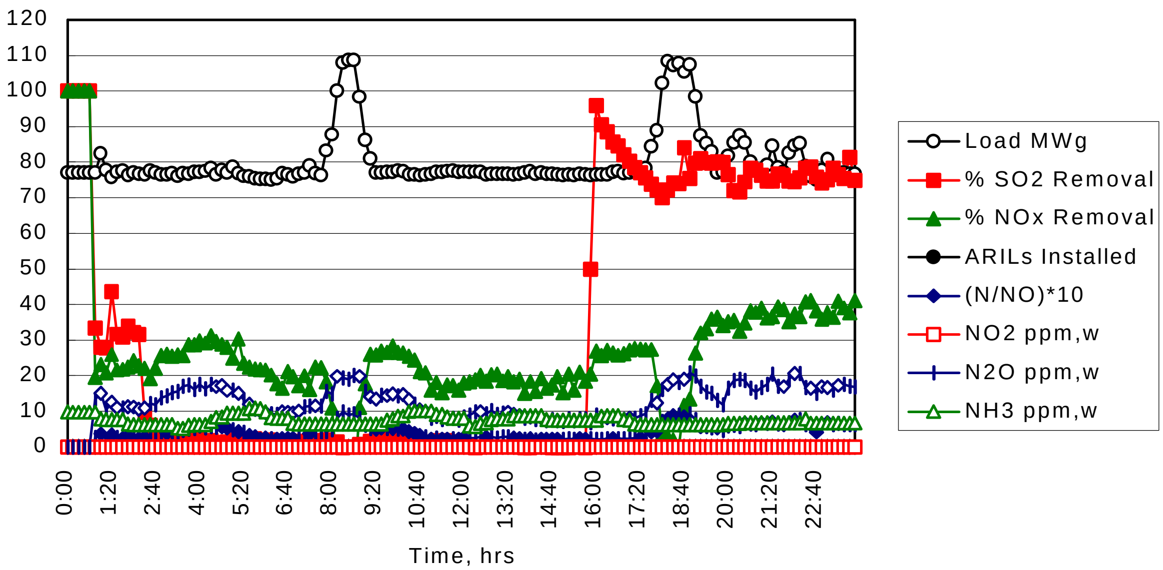


Figure 18. Long-Term Integrated Load-Following Test Results (February 29, 1996)

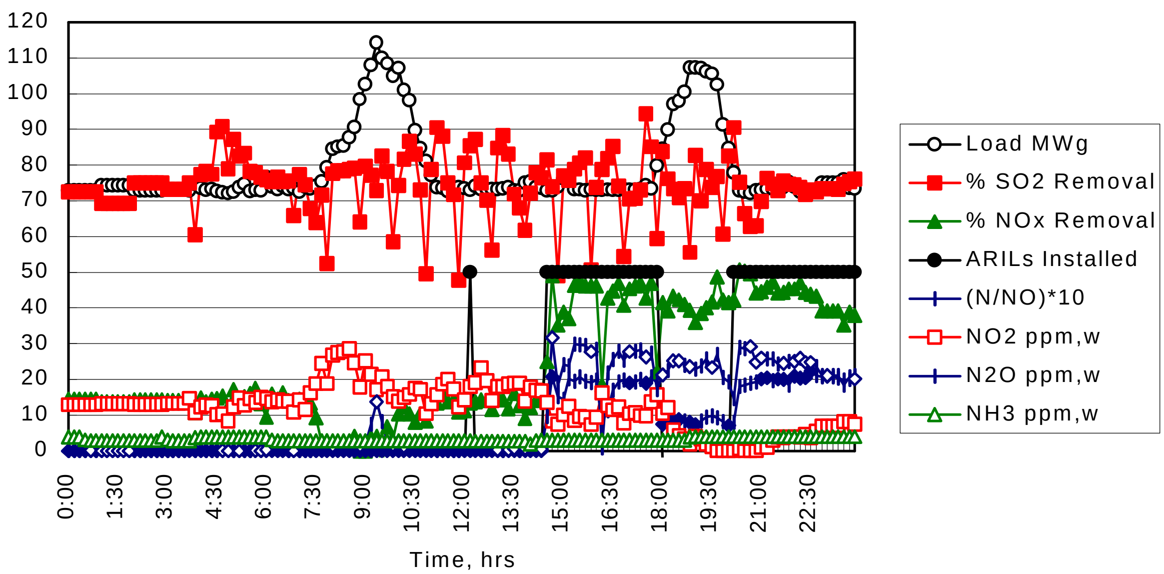


Figure 19. Long-Term Integrated Load Following Test Results (March 4, 1996)

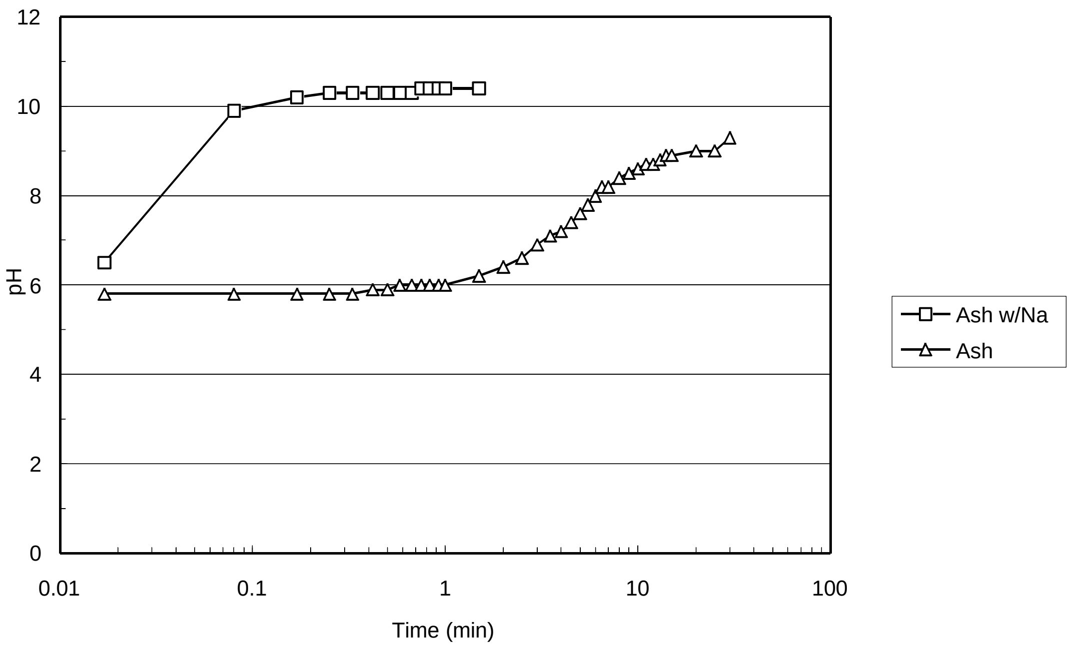


Figure 20. pH versus Time for Coal Ash and Coal Ash/Sodium Mixture
(0.5 grams of ash in 200 ml of H_2O)

Wabash River Coal Gasification Repowering Project - First Year Operation Experience Fifth Annual Clean Coal Technology Conference

E. J. (Chip) Troxclair (812-535-6050)
Destec Energy, Inc.
2500 CityWest Boulevard, Suite 150
Houston, Texas 77042

Jack Stultz (812-535-2451)
PSI Energy, Inc.
445 Bolton Road
West Terre Haute, IN 47885

ABSTRACT

The Wabash River Coal Gasification Repowering Project (WRCGRP), a joint venture between Destec Energy, Inc. and PSI Energy, Inc., began commercial operation in November of 1995. The Project, selected by the United States Department of Energy (DOE) under the Clean Coal Program (Round IV) represents the largest operating coal gasification combined cycle plant in the world. This Demonstration Project has allowed PSI Energy to repower a 1950's vintage steam turbine and install a new syngas fired combustion turbine to provide 262 MW (net) of electricity in a clean, efficient manner in a commercial utility setting while utilizing locally mined high sulfur Indiana bituminous coal. In doing so, the Project is also demonstrating some novel technology while advancing the commercialization of integrated coal gasification combined cycle technology. This paper will discuss the first year operation experience of the Wabash Project, focusing on the progress towards achievement of the demonstration objectives.

Acknowledgements

DOE Project Manager: Gary Nelkin
Participant Joint Venture Manager: Phil Amick, Destec Energy, Inc.
Demonstration Period: December, 1995 - November, 1998

Research sponsored by the U.S. Department of Energy's Morgantown Energy Technology Center, under contract DE-FC21-92MC29310 with Wabash River Coal Gasification Repowering Project Joint Venture, 2500 CityWest Blvd., Suite 150, Houston, Texas 77042: telefax: (713) 735-4837.

Introduction

When the Wabash River Coal Gasification Repowering Project Joint Venture (the JV) signed the Cooperative Agreement with the U.S. Department of Energy (the DOE) in July 1992, this marked the beginning of a truly beneficial alignment amongst the entities involved. PSI needed a clean, low cost, energy efficient baseload capacity addition that would function as a substantial element of their plan to comply with the requirements of the Clean Air Act. Also important was this projects' ability to process locally-mined (Indiana) high sulfur coal. Finally, PSI needed a project that would pass the approval of the Indiana Utility Regulatory Commission as the low cost option for baseload capacity addition.

Encouraged by the data and experience gained at its Louisiana Gasification Technology, Inc. plant (LGTI) and by the DOE Clean Coal Technology Program, Destec was interested in advancing its gasification technology to the next generation to enhance the competitive position of gasification technology for future IGCC projects.

The DOE, through its Clean Coal Round IV Program, wanted a commercial demonstration of a clean coal technology to abate the barriers to commercialization of clean coal technologies and gain data to enable power generators to make informed decisions concerning utilization of clean coal technologies.

Through the Wabash River Coal Gasification Repowering Project (the Project), the needs of the participants and the DOE are being met with this 262 MW commercial power plant. This Project is demonstrating a clean, highly efficient technology that meets today's energy demand and tomorrow's (year 2000) clean air requirements.

Overview

The Project Participants, Destec Energy, Inc. (Destec) of Houston, Texas and PSI Energy, Inc., (PSI) of Plainfield, Indiana, formed the JV to participate in DOE's Clean Coal Technology (CCT) program to demonstrate the coal gasification repowering of an existing generating unit affected by the Clean Air Act. The Participants jointly developed, but separately designed, constructed, own, and are now operating an integrated coal gasification combined cycle power plant, using Destec's coal gasification technology to repower the oldest of the six units at PSI's Wabash River Generating Station in West Terre Haute, Indiana. Destec's gasification process is integrated with a new GE 7 FA combustion turbine generator and heat recovery stream generator in repowering of a 1950's - vintage steam turbine generator using pre-existing coal handling facilities, interconnects, and other auxiliaries.

The Project has completed the first year of a three year Demonstration Period under the DOE CCT program. The early operation of the Project, which is now the world's largest single-train coal gasification combined cycle plant operating commercially, has demonstrated the ability to run at full load capability while meeting the environmental requirements for sulfur and NO_x emissions. CINergy, PSI's post-merger organization, dispatches the Project second behind their hydro facilities on the basis of environmental emissions and efficiency, with a demonstrated heat rate of approximately 9,000 Btu/KWh (HHV).

Background

Destec Gasification Technology Evolution

Destec's parent Company, the Dow Chemical Company (Dow), began the development of the Destec Gasification process in the early 1970's. Dow wanted to diversify its fuel base from natural gas to lignite and coal for its power intensive chlor-alkali processes and began to develop the gasification process through basic R&D and pilot plants. Dow's first commercial gasification plant followed, the Louisiana Gasification Technology, Inc. (LGTI) facility in Plaquemine, La. This project operated from the second quarter 1987 until the third quarter 1995 under subsidy from the Synthetic Fuels Corporation and later the Treasury Department. When Destec was formed in 1989 the gasification technology was transferred from Dow to Destec.

Wabash Project Development

Destec approached PSI in early 1990 to initiate discussions concerning the DOE Clean Coal Technology Round IV program solicitation. Through the Wabash River Coal Gasification Repowering Project Joint Venture, the project submittal was made. In September 1991, the Project was among nine projects selected from 33 proposals. The Project was selected to demonstrate the integration of Destec's gasification process with a new GE 7FA combustion turbine generator and HRSG in the repowering of an aged steam turbine generator to achieve improved efficiency and reduced emissions.

Goals of Participants

PSI wants to demonstrate an alternative technology for new units and repowering of existing units. Also PSI is incorporating this IGCC power plant into their system and wants to demonstrate this as a reliable and cost-effective element of their baseload generation capability.

Destec is demonstrating the operability, cost effectiveness and economic viability of its gasification technology in a commercial utility setting.

Destec wants to further enhance its gasification technology's competitive position by demonstrating new techniques and process enhancements as well as substantiate performance expectations and capital and operating costs.

The DOE wants to abate the barriers to commercializing clean coal technologies, particularly gasification and repowering applications, and otherwise enable power generators to make informed commercial decisions concerning the utilization of clean coal technology.

Project Organization, Commercial Structure, and Costs

There are two major agreements which establish the basis of the Project. First, the Joint Venture Agreement was created between PSI and Destec to form the Wabash River Coal Gasification Repowering Project Joint Venture in order to administer the Project under the DOE Cooperative Agreement. Second, the Gasification Services Agreement (GSA) was developed between PSI and Destec and contains the commercial terms under which the Project was developed and is now operated.

PSI Responsibilities:
build power generation facility to an agreed schedule
own & operate the power generation facility
furnish Destec with a site, coal, electric power, stormwater and wastewater facilities, and other utilities and services.

Destec Responsibilities:
build gasification facility to agreed schedule
own and operate the gasification facility
guarantee operating performance of coal gasification facility including product & by-product quality
deliver syngas and steam to the power generation facility

Project Costs

The overall combined cost of the gasification and power generation facilities was $417 million at completion. This cost includes the costs of engineering and environmental studies, equipment procurement, construction, pre-operations management (including operator training), and start-up. This figure includes escalation during the project. The start-up costs include the costs of construction and operations, excluding coal and power, up to the date of commercial operation in November 1995. Soft costs such as legal and financing fees and interest during construction are not included in this figure.

A savings of $30-40 million was realized by the repowering of the existing PSI facility, re-using the steam turbine and auxiliaries and coal handling equipment. This probably also reduced the project schedule by as much as a year, because of the simplified permitting effort versus a greenfield project.

Two areas of significant impact that increased the cost of the project were unanticipated construction problems and start-up delays. The construction effort was plagued by weather problems in the first nine months of the schedule, and later by labor shortages and construction contractor problems, that led to massive acceleration in the last 25% of the two year construction schedule. During the combined start-up of the gasification and power generation facilities, certain delays contributed to extension of the project fixed costs that also contributed to the final cost.

Project participants anticipate the costs of future units to be reduced dramatically, to the $1200/kw range for dual train facilities. Advances in turbine technology should bring the installed cost to under $1000 / kw for greenfield installations by the year 2000.

Project Schedule

The schedule for this project spans the time from selection in September, 1991 by the DOE during Clean Coal Round IV awards, to the end of the three year demonstration period in November 1998. The major project activities and corresponding milestones are as follows:

DOE Selection in Round IV	September	1991
Cooperative Agreement Finalized	August	1992
Environmental Assessment Complete	May	1993
State Air Permits Complete	May	1993
Indiana Utility Regulatory Approval Complete	May	1993
Began Construction	September	1993
Completed Construction	July	1995
First Coal Operation	August	1995
Began Commercial Operation	November	1995
Began Demonstration Period	December	1995
Complete Demonstration Period	November	1998
Final Report	February	1999

This aggressive schedule was possible by overlapping of activities between the development and engineering periods as well as the engineering and construction periods.

Review of Technology

General Design and Process Flow

The Destec coal gasification process features an oxygen-blown, continuous-slagging, two-stage, entrained-flow gasifier which uses natural gas for startup. Coal is milled with water in a rodmill to form a slurry. The slurry is combined with oxygen in mixer nozzles and injected into the first stage of the gasifier, which operates at 2600 F and 400 psig. Oxygen of 95% purity is supplied by a turnkey, 2060-ton/day low-pressure cryogenic distillation facility which Destec owns and operates.

In the first stage, coal slurry undergoes a partial oxidation reaction at temperatures high enough to bring the coal's ash above its melting point. The fluid ash falls through a taphole at the bottom of the first stage into a water quench, forming an inert vitreous slag. The syngas then flows to the second stage, where additional coal slurry is injected. This coal is pyrolyzed in an endothermic reaction with the hot syngas to enhance syngas heating value.

The syngas then flows to the High Temperature Heat Recovery Unit (the HTHRU), essentially a firetube steam generator, to produce high pressure saturated steam. After cooling in the HTHRU, particulates in the syngas are removed in a hot/dry filter and recycled to the gasifier where the carbon in the char is converted into syngas. Filter-element construction is a proprietary design proven at full scale at LGTI. The syngas is further cooled in a series of heat exchangers and passed through a catalyst which hydrolyzes carbonyl sulfide into hydrogen sulfide. Hydrogen sulfide is removed using MDEA-based stripper columns. The "sweet" syngas is then moisturized, preheated, and piped over to the power block.

The key elements of the power block are the General Electric MS 7001 FA high-temperature combustion turbine/generator, the heat recovery steam generator (the HRSG), and the repowered steam turbine.

The GE 7FA is a dual-fuel machine (syngas for operations and No. 2 fuel oil for startup) capable of a nominal 192MW when firing syngas, which is attributed to the increased mass flows associated with syngas. Steam injection is used for NOx control, but the steam flow requirement is minimal compared to conventional systems because the syngas is moisturized at the gasification facility, making use of low-level heat in the process. The water consumed in this process is continuously made up at the power block by water treatment systems which clarify and treat river water.

The HRSG for this project is a single-drum design capable of superheating 754,000 lb/hr of high-pressure steam at 1010 F, and 600,820 lb/hr of reheat steam at 1010 F when operating on design-basis syngas. The HRSG configuration was specifically optimized to utilize both the gas-turbine exhaust energy and the heat energy made available in the gasification process. The nature of the gasification process in combination with the need for strict temperature and pressure control of the steam turbine led to a great deal of creative integration between the HRSG and the gasification facility.

The repowered unit, originally installed in 1952, consisted of a conventional coal-fired boiler feeding a Westinghouse reheat steam turbine rated at 99MW but derated in recent years to 90MW for environmental dispatch. Repowering involved refurbishing the steam turbine to both extend its life and withstand the increased steam flows and pressures associated with the combined cycle operation.

The repowered steam turbine produces 104MW which combines with the combustion turbine generator's 192MW and the system's auxiliary load of approximately 34MW to yield 262MW (net) to the CINergy grid.

At the design point, the Air Separation Unit (ASU) provides oxygen and nitrogen for use in the gasification process but is not an integral part of the plant thermal balance. The ASU uses services such as cooling water and steam from the gasification facilities and is operated from the gasification plant control room.

The gasification facility produces two commercial byproducts during operation. Sulfur removed as 99.9 percent pure elemental sulfur is marketed to sulfur users. Slag will be sold as aggregate in asphalt roads and as structural fill in various types of construction applications.

Technical Advances

Using integrated coal gasification combined cycle technology to repower a 1950's-vintage coal-fired power generating unit essentially demonstrates a technical advance in and of itself.

More specifically, high energy efficiency and superior environmental performance while using high sulfur bituminous coal is the result of several improvements to Destec's gasification technology, including:

Hot/Dry Particulate Removal, applied at full commercial scale with no provision for bypass.
Syngas Recycle, which provides fuel and process flexibility while maintaining high efficiency.
A High Pressure Boiler, which cools the hot, raw gas by producing steam at a pressure of 1,600 psia.
A Dedicated Oxygen Plant, which produces 95% pure oxygen for use by the Project. Use of 95% purity increases overall efficiency of the Project by lowering the power required for production of oxygen.
Integration of the Gasification Facility with the Heat Recovery Steam Generator to optimize both efficiency and operating costs.
The Carbonyl Sulfide Hydrolysis system, which allows such a high percentage of sulfur removal.
The Slag Fines Recycle system, which recovers carbon remaining in the slag byproduct stream and recycles it back for enhanced carbon conversion. This also results in a higher quality byproduct slag.
Fuel Gas Moisturization, which uses low-level heat to reduce steam injection required for NO_x control.
Sour water treatment and Tail Gas Recycling, which allow more complete recycling of combustible elements, thereby increasing efficiency and reducing waste water and air emissions.

The Project's superior energy efficiency is also attributable to the power generation facilities included in the Project. These facilities incorporate the latest advancements in combined cycle system design while accommodating design constraints necessary to repower the steam turbine, including:

The Project is the first application of Advanced Gas Turbine technology for syngas fuel, incorporating redesigned compressor and turbine stages, higher firing temperatures and higher pressure ratios, specially modified for syngas combustion.

Repowering of the Existing Steam Turbine involved upgrading the unit in order to accept increased steam flows generated by the HRSG. In this manner, the cycle efficiency is maximized because more of the available energy in the cycle is utilized.

Operations Experience

The Project completed the commissioning phase in August of 1995 and began the start-up process. By late August, the gasifier was ready for coal feed. The Project was in the start-up and testing mode through mid November at which time the start-up tests were complete and the Project was ready for the commercial operation and demonstration phase to begin. Significant in the start-up phase was the successful demonstration of the thermal integration of the combined operations. There were no substantial problems integrating the steam and water systems, although some early feedwater control problems contributed to early operation interruptions that carried over to the commercial operating period. These problems have since been resolved. The startup phase also demonstrated product (syngas) and by-product (slag & sulfur) quality and environmental performance.

Demonstration Period Test Plan

With this project being a full scale commercial unit in a utility environment, the Test Plan for the Demonstration Period focuses on successful operation of the plant as a base-load unit in the PSI system. Specifically, the goals of the participants for the Demonstration Test Plan primarily address continuous improvement in plant availability, operating and maintenance costs, maintaining dispatch, and improvement in overall performance while fulfilling the reporting requirements for environmental performance and equipment/system performance. Towards these goals, the next section will address the first year of performance under the three year demonstration period.

Operations Statistics/Milestones

The early commercial operation of the WRCGRP saw the plant build on the success of the start-up period with primary focus on attaining maximum sustained capacity for the purpose of final performance testing for the Air Separation Unit (ASU) Facility and Gasification Plant. The ASU Performance Testing was completed in February 1996 during an operating campaign that lasted over 300 hours. In March 1996 just four months into the operating period, the gasification plant demonstrated extended operation at 100% of rated design by running over 100 hours at or above gasifier design capacity. During these February and March operating campaigns the combustion turbine ran smoothly on syngas and had periods of operation at the 192 MW maximum rated capacity on syngas.

As the Project accumulated the early run time, evaluation of the technical advances noted previously showed that most of the new unit operations performed very well, however two of the areas contributed problems which affected run time. The primary problem area has been the reliability of the particulate removal system, primarily due to breakage of ceramic candle filters. Further testing and modifications to the particulate removal system are underway to minimize element breakage. Another problem area was chloride concentrations in both the COS hydrolysis catalyst beds and downstream heat exchangers in the syngas cooler line-up. Unexpected localized high chloride concentrations contributed to catalyst poisoning and chloride stress corrosion cracking in the low temperature syngas heat exchangers. A scrubber system has been installed to remove the chlorides from the syngas prior to the COS hydrolysis beds and syngas heat exchangers. These modifications are in place as the plant moves into the second operating year.

On the Power Block side the new Advanced Gas Turbine has performed very well on syngas. The turbine's operation has been more stable on syngas than on oil, with blade temperatures more evenly distributed and less temperature spiking. NO_x is controlled with steam injection to meet air permit requirements. The turbine experienced three problem areas after the acceptance of syngas. The first was in the syngas module and the piping from the module to the gas turbine. Expansion bellows required redesign and replacement to eliminate mechanical cracking in the flow sleeves. This problem was corrected by GE efforts in early syngas runs. The second problem has been the syngas purge control. These problems were primarily related to field devices such as solenoid valves and flow measuring devices. The solenoids have been redesigned and replaced and GE continues to work on flow measuring devices. The third area was the GE required row 2-3 spacer modifications, a fleet problem unrelated to syngas utilization.

Table I shows the production statistics for both the Gasification plant and combined cycle plant through October 1996.

Gasification Plant Production Statistics

First Coal Gasified August 17, 1995

Total Gasifier Hours on Coal*	2035
Total Syngas produced*	2,814,066 MMBtu (Dry)
Total Coal Processed*	189,233 Tons
Highest Capacity Demonstrated (% Nameplate)	103% (1825 MMBtu/hr, HHV)
Longest Continuous Coal Run* (Hours)	253
Cold Gas Efficiency (%)	>74%

Combined Cycle Plant Production Statistics

First Syngas to Combustion Turbine (C.T.) October 3, 1995

Total C.T. Hours*	2872
Total C.T. Hours on Syngas*	1340
MWH'S produced on Syngas*	333,486
Highest C.T. Capacity Demonstrated (% Nameplate)	100% (192 MW)
Longest Continuous Syngas Operation* (Hours)	151

*(All Production Statistics through October 1996)

TABLE I

Following is an operations summary of each major operating area, including the areas mentioned above, with a discussion of the process modifications incorporated to address the early problems encountered.

Area Operations Summaries

Coal Slurry Preparation

Coal is ground into a slurry in a rodmill, using recycled water from the gasification process. Wet milling reduces potential fugitive particulate emissions and minimizes water consumption and effluent waste water volume. The slurry is stored in an agitated tank large enough to supply the gasifier during rodmill forced outages.

The slurry preparation area has now processed (189,233) tons of coal with no significant problems. Typical problems handling coal during low ambient temperature conditions and heavy snowfall were experienced, primarily with the automatic sampling equipment, but the slurry has consistently met target solids concentration. The slurry storage and feed systems have also performed very well since the beginning. Typical Coal properties are shown in Table II.

COAL PROPERTIES	
Moisture	5-15%
Ash	5-15%
Sulfur (dry)	2.3 - 5.9%
Ash fusion temperature	2000-2500 F
Heating Value (MAF)	Over 13,500 Btu/lb (HHV)

TABLE II

Oxygen/Nitrogen Generation and Supply

The Air Separation Unit (ASU), supplied by Liquid Air Engineering Co. (LAEC), produces 2060 t/d oxygen at 95% purity as well as high purity nitrogen and dry process air for use in the gasification process. The process involves air compression, purification, cryogenic distillation, oxygen compression, and a nitrogen storage and handling system. After modifications to improve nitrogen production the ASU has reliably supplied products to the gasifier island at specified quantities and quality.

Gasification and Slag Handling

The two stage Destec gasifier operates with a slagging first stage and an entrained flow second stage. Coal slurry and oxygen are fed to the first stage as well as recycled char from the particulate removal system. This stage operates at 2600 F, producing syngas which exits to the second stage. Molten slag exits the first stage through a taphole and is quenched in a water bath prior to removal through Destec's continuous slag removal system. The second stage of the gasifier uses additional coal slurry and recycled syngas to lower the temperature to 1900 F. Raw syngas exits the gasifier enroute to the syngas cooler.

The gasification and slag handling areas have performed very well thus far. Slag removal has been essentially trouble free since the beginning. The gasifier has consistently processed the coal into high quality syngas.

Syngas Cooling, Particulate Removal, and COS Hydrolysis

Syngas containing entrained particulates exit the gasifier and is cooled in a firetube heat recovery boiler system, producing 1600 psig saturated steam. Cooled raw gas leaving the boiler passes through a barrier filter unit to remove particulates (char) for recycle to the first stage of the gasifier. The particulate free gas is further cooled prior to entering the COS hydrolysis unit where COS in the raw gas is converted to H_2S for removal in the Acid Gas Removal system. This area of the gasification plant has experienced problems which can be summarized into three areas: (1) Ash accumulation at the inlet to the firetube boiler, (2) particulate breakthrough from the barrier filter system, and (3) poisoning of the COS catalyst due to chlorides and trace amounts of arsenic in the syngas.

Ash deposition has not been a major contributor to overall downtime, but has limited runtime somewhat due to ash accumulation at the inlet to the boiler tubes. Improvements have been incorporated to reduce and manage this ash, and more improvements are planned.

Particulate breakthrough has been primarily due to movement and breakage of the ceramic candle filter elements. Substantial downtime is associated with entry into the particulate filter vessels, therefore there has been significant emphasis on improvements to this system. These improvements will be implemented during the third quarter and fourth quarter of 1996.

Poisoning of the COS catalyst due to chlorides and trace arsenic led to early replacement of the catalyst. To address this concern as well as metallurgy concerns with chlorides further downstream in the process, a scrubber system has been installed. The scrubber has satisfactorily resolved these problems.

Low Temperature Heat Recovery and Syngas Moisturization

After exiting the COS hydrolysis unit, low level heat is removed from the syngas in a series of shell-and-tube heat exchangers prior to Acid Gas Removal. This low level heat is used for syngas moisturization, stripping of the acid gases in the Acid

Gas Removal system, and preheating condensate. This section of the process has performed well in terms of providing the moisturization for the syngas and providing heat transfer as designed. However, localized chloride stress corrosion cracking to some of these exchangers necessitated replacement with alternate metallurgy. The scrubber mentioned earlier in addition to protecting the COS catalyst, has eliminated metallurgy concerns in this section of the process.

Acid Gas Removal and Sulfur Recovery

The Acid Gas Removal system consists primarily of an H_2S absorber column and an H_2S stripper column. H_2S is removed from the syngas in the absorber using a solvent (MDEA) and the syngas is then routed to the moisturizer column mentioned previously. The H_2S absorbed is stripped and routed to the Claus process where it is converted to elemental sulfur. The remaining small amount of unconverted H_2S in the acid gas is compressed for recycle to the gasifier. During process upsets, the spent acid gas is sent to an incinerator, which is one of the permitted air emissions sources. The Acid Gas Removal process has effectively demonstrated removal of over 99% of the sulfur in the syngas. The typical product syngas composition from the plant is shown in Table III.

TYPICAL PRODUCT SYNGAS COMPOSITION

Component	**Volume Percent**
Hydrogen (H_2)	28
Carbon Monoxide (CO)	38
Carbon Dioxide (CO_2)	10
Methane (CH_4)	1
Nitrogen (N_2)	1
Water (H_2O)	22
Sulfur Compounds	<50 ppmV
Heating Value (dry)	285 Btu/scf (HHV)

TABLE III

Environmental Performance

Total sulfur dioxide emissions from the three permitted emissions points (HRSG stack, gasification flare stack, and tail gas incinerator stack) have demonstrated the ability of the gasification process to successfully operate below 0.2 lbs/MMBtu of coal input. To date, emission rates of less than 0.1 lbs/MMBtu have been attained. This represents a 94% reduction in SO_2 emissions from the decommissioned Unit

1 boiler at Wabash River. The 0.2 lbs/MMBtu is significantly below Acid Rain limits for the year 2000, which are set at 1.2 lbs/MMBtu under the Clean Air Act.

Sour Water Treatment

Sour water is condensed from the syngas in the low temperature heat recovery section of the gasification plant. This water is primarily used for recycle to the slurry preparation plant. The recycled water is stripped of all dissolved gases except ammonia, which remains in the recycled water. Excess water is stripped of all dissolved gases and discharged through a permitted outfall. The sour water treatment system has performed well.

Combustion Turbine

The combustion turbine has operated in excess of (2800) fired hours on syngas and No 2 fuel oil. The turbine has operated in the designed baseload configuration and as a liquid fuel fired combined cycle peak service generator. Both modes of operation have proven to be stable and viable options for the operation of the generator on the bulk power system. The combustion turbine control system (Mark V) has proven, after initial startup tuning, to be reliable and maintainable by on-site PSI technicians. This system does require formal training for the technicians to develop the necessary skills for long term maintenance. Technicians were trained to maintain Gas Turbine Controls (Mark V), the excitation system (EX2000) and the Gas Turbine cranking system, (LCI). On site control maintenance capability is critical to establishing an available and reliable Gas Turbine.

Steam Turbine

The steam turbine is an early 1950’s vintage Westinghouse reheat turbine. The original nameplate for the steam turbine was 99MW, but the repowered rating is 104MW due to the removal of the steam extractions. Throttle pressure has been maintained at the original 1450 psig and throttle temperature is 1005 F. The steam turbine and turbine auxiliaries are located approximately 1600 feet from the gas turbine power block and consequently required extensive piping and drains installations. Although the steam turbine is remotely located with respect to the new power block, the steam turbine operation interface is in the new control room with the new power block controls, Westinghouse WDPF.

Additional modifications were required to the repowered steam turbine as follows. The condensate and feedwater heating extractions were removed and capped. The cold reheat extraction was inspected and maintained for the repowered operation. One row of blading was replaced in the low pressure turbine as a result of the repowering. The generator was rewound and the generator rotor was replaced.

A new static excitation system was installed to improve the reliability. The hydraulic turbine controls were replaced with the Westinghouse DEH control system. Existing Turbine Supervisory Instrumentation (TSI) was left in place and remains functional.

The turbine experienced a control shaft failure during the early operation due to an improperly sized cold reheat orifice causing the rotor to thrust, resulting in the failure. Otherwise, the steam turbine has operated very well in the new configuration.

Water Treatment

Water treatment was designed to meet the needs of both the power block and the gasification island. Surface water is drawn from the Wabash River and clarified with a CBI Claricone, filtered then metered to various demands at both operating blocks of the project. Some filtered water is treated in two parallel 480 gpm demineralizers. There is 750,000 gallons of demineralized water storage capability. This water is the supply for the steam cycles of the power block and the gasification island. The control of the water facility is also included in the scope of the Westinghouse WDPF system and can be operated from the central control room. Operation of the water facility has been reliable and cost effective.

OUTLOOK/SUMMARY

Through the first year of the demonstration period, the Wabash River Coal Gasification Repowering Project has made good strides towards achieving the Project Goals. Both the Gasification and Combined Cycle Plants have demonstrated the ability to run at capacity and within environmental compliance while using locally mined coal. The technology advancements which made this a DOE demonstration project have, for the most part, operated well. Modifications were made to address those problem areas identified through the early operation experience, modifications which have improved plant operation and will further allow demonstration of the Project Goals as the project moves into the second year of the demonstration period.

References

Woodruff, M.R., Destec Energy, Inc., "Wabash River Project Moves into Commercial Operation," *U.S. Department of Energy Fourth Annual Clean Coal Technology Conference Proceedings* (Denver Colorado), September 5-8, 1995.

Troxclair, E.J., Breton, D.L., Amick, P., Destec Energy, Inc. and Stultz J., PSI Energy, "Wabash River Coal Gasification Repowering Project - Early Commercial Operation Experience," *Thirteenth Annual International Pittsburgh Coal Conference Proceedings* (Pittsburgh, Pennsylvania), v1, p 436; September 1996.

McIntosh Unit 4 PCFB Demonstration Project

Alfred M. Dodd
Project Manager
Lakeland Electric & Water
501 E. Lemon Street
Lakeland, FL 33801

Richard J. Dryden
Project Manager
Foster Wheeler Development Corporation
P.O. Box 85480
San Diego, CA 92186

Harry T. Morehead
Manager New Program Development
Westinghouse Electric Corporation
4400 Alafaya Trail
Orlando, FL 32826

Introduction

The City of Lakeland, Foster Wheeler Corporation and Westinghouse Electric Corporation have embarked on a utility scale demonstration of Pressurized Circulating Fluidized Bed (PCFB) technology at Lakeland's McIntosh Power Station in Lakeland, Florida. The U.S. Department of Energy will be providing approximately $195 million of funding for the project through two Cooperative Agreements under the auspices of the Clean Coal Technology Program. The project will involve the commercial demonstration of FOSTER WHEELER PYROFLOW® PCFB technology integrated with Westinghouse's Hot Gas Filter (HGF) and power generation technologies.

The total project duration will be approximately eight years and will be structured into three separate phases; two years of design and permitting, followed by an initial period of two years of fabrication and construction and concluding with a four year demonstration (commercial operation) period. It is expected that the project will show that Foster Wheeler's Pyroflow PCFB technology coupled with Westinghouse's HGF and power generation technologies represents a cost effective, high efficiency, low emissions means of adding greenfield generation capacity and that this same technology is also well suited for repowering applications.

Background

The City of Lakeland, Department of Electric & Water Utilities (Lakeland) is a municipally owned and operated electric and water utility in Central Florida. Lakeland is conveniently located between Tampa and Orlando which has allowed Lakeland to grow and prosper over its 92 year history. Lakeland is the third largest municipal utility in the State of Florida serving more than 104,000 electric customers and also has residential rates that are currently the second lowest of all Florida utilities. Despite enjoying low electric rates and steady load growth, Lakeland is not immune to competition. Competition is driving all utilities to find ways not only to prevent cost growth but to also lower costs. A heightened awareness of the environment by the general public and Lakeland's customers is also maintaining the pressure for "clean" electric generation. Traditionally these two goals have not been complimentary in that environmental compliance normally has meant an increase in generation costs to achieve that compliance. This raises the question each utility must soon face: how to provide new generating capacity, needed for growth and replacement of retired capacity, at a competitive cost while meeting stringent environmental requirements.

Lakeland has experienced and is forecasting steady load growth within its municipal system of approximately 15 MW per year which will result in a capacity shortfall in the year 2000 of approximately 45 MW. In addition to the pending capacity shortfall, Lakeland wishes to retire 50 MW of very old and inefficient existing generating capacity. Considering both of these issues and future needs, Lakeland needs to bring on line at least 150 MW of additional generating capacity by the year 2000.

In today's competitive environment, the prospects of adding additional capacity in itself can bring many uncertainties. With the majority of Lakeland's capacity already tied to one fuel that has greater uncertainties in such areas as price and availability, the need to add more capacity led Lakeland to look closely once again at America's most abundant fuel source, coal. Lakeland's current mix of resources include approximately 200 MW of base load pulverized coal and 450 MW of intermediate/peaking gas capacity. This capacity is divided between two power stations that Lakeland owns which are located within the city limits on the shores of Lake Parker. The larger of the two power stations is the McIntosh station on the north side of Lake Parker with approximately 590 MW[1] of generating capacity while the smaller Larsen station on the south side of the lake has about 230 MW of generating capacity.

Lakeland was a pioneer of sorts when the 334 MW McIntosh 3 unit went on-line in 1982. The unit was one of the first "scrubbed", zero-discharge coal units in the nation. Today, Lakeland is looking to be a pioneer again by partnering with Foster Wheeler Corporation and Westinghouse Electric Corporation to build and operate a utility scale demonstration of PCFB technology (unit 4) at Lakeland's McIntosh Plant site. The addition of McIntosh unit 4 will provide Lakeland with new, cost competitive and environmentally clean coal based capacity for the 21st Century. The added capacity that this unit will provide will not only add to Lakeland's fuel diversity, but will provide energy at some of the lowest costs per megawatt hour of any generating source in the Southeast. These factors combined with the state of the art pollution controls provided by the Foster Wheeler PCFB process and the Westinghouse HGF technology will ensure that McIntosh unit 4 will keep Lakeland very competitive and environmentally acceptable well into the future. The successful construction and operation of this technology will provide utilities with a means of adding needed generating capacity in a manner that is consistent with the competitive and environmental challenges that all are facing.

---

[1] McIntosh Unit 3 is a 334 MW pulverized coal unit that is jointly owned by Lakeland and the Orlando Utilities Commission.

Project Structure

The proposed McIntosh Unit 4 PCFB Demonstration Project would be constructed as two sequential demonstrations that would demonstrate both PCFB and Topped PCFB technology. There are two primary reasons for this proposed project structure:

(i) The DOE funding being provided for the project results from a combination of two previous Clean Coal awards: the DMEC-1 PCFB Repowering Project (DMEC-1) selected under Round III and the Four Rivers Energy Modernization Project (FREMP) selected under Round V. The DMEC-1 project was intended to demonstrate PCFB technology while the FREMP project was planning to demonstrate Topped PCFB technology. By utilizing a sequential approach with the McIntosh Unit 4 PCFB project, it will be possible to demonstrate both PCFB (1st Demonstration) and Topped PCFB (2nd Demonstration) technology in the same project, thereby satisfying the objectives of both the DMEC and FREMP projects.

(ii) Additional development work is required on certain components of the Topped PCFB cycle prior to the construction of the same components at a commercial scale. Specifically, additional development is required for the Westinghouse topping combustor (multi-annular-swirl-burner or MASB) including the demonstration of MASB operation at low outlet oxygen levels. Important aspects of Westinghouse's MASB development work have been and will be conducted at the University of Tennessee Space Institute. Some additional development work may also be performed for other components of the carbonizer system. Development on the carbonizer system has been performed at Foster Wheeler's John Blizzard Research Center in Livingston, New Jersey. Both of these systems are incorporated in the Wilsonville Power Systems Development Facility (PSDF) facility at a Southern Company operated site in Wilsonville, Alabama that will shortly be starting operation. The combination of the above programs is expected to provide Westinghouse and Foster Wheeler with the necessary information required to finalize the design of the carbonizer and MASB's in time to support the demonstration of Topped PCFB technology.

The project schedule (discussed in more detail below) anticipates the start of commercial operation of the 1st Demonstration in the winter of the year 2000. In parallel with the first two years of operation of the 1st Demonstration will be the design, fabrication and construction of the 2nd Demonstration culminating in a planned start of operation of late 2002 for the combined facility.

Project Objectives

Through the sequential demonstration of both PCFB and Topped PCFB technology it has been possible to preserve the objectives of both the original Cooperative Agreements described in the preceding section. The objectives governing the agreement relating to PCFB technology include the demonstration of PCFB technology to provide for the potential commercialization of the technology in the 21st century and to provide the capability of achieving significant reductions in the emissions of sulfur oxide and nitrogen oxides from existing facilities when they are repowered with PCFB technology.

The objectives for the agreement relating to Topped PCFB technology call for the demonstration of the technology in a "fully commercial power generation setting" which is certainly the case at the McIntosh site as is further explained below. All the key components of the Topped PCFB technology will be demonstrated thereby paving the way for future plants that will operate at higher gas turbine inlet temperatures and that are expected to provide cycle efficiencies in excess of 45%. Additional objectives relating to the Topped PCFB technology that will be proven through a successful demonstration include reductions in sulfur oxide emissions of as much as 95% and nitrogen oxide emissions as low as 0.17 lb/MMBTU of heat input.

Process Description

PCFB technology is a combined cycle power generation system that is based on the pressurized combustion of solid fuel to generate steam in a conventional Rankine cycle combined with the expansion of hot pressurized flue gas through a gas turbine in a Brayton cycle. The technology can be subdivided into the basic PCFB cycle ("First Generation") and Topped PCFB cycle ("2nd Generation" or "Advanced PCFB"). In the PCFB cycle, hot pressurized flue gas is expanded through the gas turbine at a temperature of less than 1650ºF. Topped PCFB cycles include a coal carbonizer (mild gasifier) to generate a low BTU fuel gas which is used to fire the inlet of the gas turbine (in a topping combustor or MASB) and increase the gas turbine inlet temperature from a less than 1650°F up to 1900° - 2300ºF or higher. Both versions of PCFB technology offer high cycle efficiencies and ultra low emissions. More detailed descriptions of the PCFB and Topped PCFB cycles are provided below.

Figure 1 presents a simplified schematic of the 1st Demonstration of the McIntosh Unit 4 PCFB Demonstration Project incorporating a PCFB cycle. Combustion air is supplied from the compressor section of the gas turbine to the PCFB combustor located inside a pressure vessel. Coal and limestone are mixed with water into a paste which is pumped into the combustion chamber using piston pumps commonly used in the concrete industry. The same type of pumps have been successfully proven in a number of pressurized fluidized bed combustion (PFBC) coal projects around the world.

Combustion takes place at a temperature of approximately 1560° - 1600ºF and at a pressure of about 200 psig. The resulting flue gas and fly ash leaving the cyclone enter the hot gas filters where dust removal takes place. The hot gas filters are a Westinghouse design based closely on the filter supplied to the Sierra Pacific Piñon Pine project in Tracy, Nevada. In addition to the Piñon Pine project, a Westinghouse filter has undergone approximately 6000 hours of testing at Ohio Power's Tidd PFBC Demonstration facility in Brilliant, Ohio (Round I project). A full scale commercial module of this type of ceramic candle filter has also undergone more than 6000 hours of extensive testing at Foster Wheeler's PCFB test facility in Karhula, Finland.

The hot clean gas leaving the filter is expanded through the gas turbine before passing through a heat recovery unit and entering the stack. Heat recovered from the cycle from both the combustor and the heat recovery unit is used to generate steam to power a reheat steam turbine. Approximately 15% of the gross power output is derived from the gas turbine with the steam turbine contributing the remaining 85%.

The gas turbine technology is based on a standard Westinghouse 251B12, single shaft, cold end drive industrial machine that has had the center section of the turbine modified. A scroll section has been added to allow for the removal of compressor discharge air from the casing for external firing in the PCFB combustor and to allow for the introduction of hot clean gas back through the casing into the expander section. This air outlet/gas inlet configuration has been previously applied in recuperative gas turbine cycles. The gas inlet temperature of less than 1650ºF allows for a simplified turbine shaft and blade cooling system. This combined with low excess air operation in the PCFB combustor provides a maximum amount of steam generation per unit mass of air from the gas turbine and therefore maximizes power output from the cycle.

Figure 2 shows the process flow arrangement of the 2nd Demonstration of the McIntosh Unit 4 PCFB Demonstration Project. This involves the addition of a carbonizer island which includes a topping combustor (MASB) to convert the PCFB cycle to a Topped PCFB cycle. Through the addition of this equipment, the inlet temperature to the gas turbine is increased via the combustion of coal derived "syngas". This has the effect of increasing the cycle power output while simultaneously improving the net plant heat rate. Natural gas can also be used as the topping fuel thereby providing a backup to the operation of the carbonizer island.

In the top right hand corner of Figure 2, the carbonizer island is shown. Dried coal and limestone are fed via a lock hopper system to the carbonizer together with part of the gas turbine compressor discharge air. The coal is partially gasified or carbonized at about 1700°F to produce a syngas and char solids stream. The limestone is used to absorb sulfur compounds generated during the mild gasification process and to catalyze the gasification process. After cooling the syngas to about 1200°F, the char and limestone entrained with the syngas are removed by a Westinghouse hot gas filter. The char and limestone are transferred to the PCFB combustor for complete carbon combustion and limestone utilization. The hot clean filtered syngas is then fired in a topping combustor (MASB) to raise the turbine inlet temperature to almost 2000°F. The gas is expanded through the turbine, cooled in a heat recovery unit and exhausted to the stack. As in the case of the previous cycle, combustion air is supplied to the PCFB combustor from the compressor section of the gas turbine. Coal and limestone are again fed to the PCFB combustor in paste form but are supplemented by the char transferred from the carbonizer as discussed above.

Performance

The First Demonstration would involve a basic PCFB cycle that would come on line in the year 2000 and would provide approximately 157 MW of coal-fired generating capacity. The cycle would have a gas turbine inlet temperature of approximately 1550°F. Following the completion of some additional development work, the Second Demonstration of the project would be constructed and brought on line approximately two years later. This would entail the conversion of the 1st Demonstration PCFB system to a Topped PCFB system through the addition of a carbonizer island and a topping combustor. The addition of the carbonizer system would generate a coal derived, low BTU synthesis gas that would be fired at the inlet of the gas turbine to raise the turbine inlet temperature to approximately 1975°F. The net impact of this equipment addition would be an additional 12 MW of power output with an associated improvement in heat rate of about 600 BTU/kWhr for the entire plant.

The project would be constructed as McIntosh Unit 4 within the boundaries of existing station on land owned by the city. The new unit will be designed to burn a range of coals including both the current Eastern Kentucky coal burned in unit 3 and high ash, high sulfur coals that are expected to be available in the future at substantially lower prices than mid to low sulfur bituminous coals. Limestone would be sourced from a number of nearby Florida limestone quarries while ash would be disposed of in a landfill or marketed to others.

The majority of the project's water makeup requirements will be met using secondary treated sewage effluent for cooling tower makeup while the use of sewage "sludge" (3 - 4% solids) is being considered for preparation of the coal-water paste mixture that is pumped into the PCFB. Service water will be used only for boiler water makeup feed to the demineralizer system. Wastewater from the unit will be treated on site for neutralization and removal of heavy metals before being returned to the Glendale waste water treatment facility (owned by Lakeland) for discharge. Gaseous emissions from the plant will be controlled using state of the art technology and will be representative of recent best available control technology (BACT) determinations in Florida.

Project Schedule

The City of Lakeland wishes to have the 1st Demonstration plant enter commercial operation during the winter of the year 2000. Prior to commencing fabrication and construction (Phase 2) of the new facility, the permitting and licensing process required by the state of Florida must be completed. In addition, DOE requires that the National Environmental Policy Act (NEPA) process be completed prior to DOE providing any funds for the purpose of fabricating and constructing the facility.

The NEPA and permitting/licensing processes are each expected to take 20 months to complete and are parallel critical path activities dictating the duration of Phase 1 of the project. At the time of writing, Phase 1 was expected to begin around December 1, 1996 following the formal execution of the Cooperative Agreements by Lakeland and DOE. Phase 2 begins with the general release for fabrication and construction for the 1st Demonstration and lasts for a total of 53 months. Phase 3 has an overall duration of 48 months. The first 29 months of Phase 2 cover the period from the end of Phase 1 through to the start of Phase 3 during which the 1st Demonstration facility is fabricated and constructed. The second 24 months of Phase 2 overlap with Phase 3 and cover the time required to design, engineer, fabricate and construct the 2nd Demonstration equipment.

Phase 3 will be structured in two segments: an initial two year period while the PCFB technology of the 1st Demonstration is demonstrated, and a subsequent two year period during which the Topped PCFB technology of the 2nd Demonstration will be operated. The additional equipment required for the 2nd Demonstration will be engineered, procured and constructed in parallel with the operation of the 1st Demonstration during the first two years of Phase 3. All efforts will be made to minimize the amount of downtime of the facility required to connect the 2nd Demonstration equipment to the 1st Demonstration plant.

Figure 3 presents an overview of the anticipated project schedule.

Project Cost and Funding Summary

The total cost and funding summaries for McIntosh Unit 4 PCFB Demonstration Project in "as spent" dollars are shown below. The total project costs include the total cost to construct the facility, certain project related offsite costs, 4 years of operation and maintenance (O&M) costs, owner's costs and permitting costs.

		($1000)
COSTS	Total Project Costs	387,970
	Lakeland In-Kinds	2,030
	TOTAL COSTS	**390,000**
FUNDS	Lakeland In-Kinds	2,030
	Lakeland	192,970
	DOE	195,000
	TOTAL FUNDS	**390,000**

The total McIntosh Unit 4 PCFB Demonstration project costs have been divided between the two Cooperative Agreements.

Participant Project Financing

The City of Lakeland has a number of financing alternatives to use for the project. Lakeland has accumulated reserves for future expansion and system general purpose uses. These funds are available for use by the City's Department of Electric & Water Utilities and part of them have been earmarked for the McIntosh Unit 4 PCFB Demonstration Project.

Lakeland also enjoys very favorable bond ratings due to its long-standing financial health. Recently, the drop in interest rates was found to be financially favorable for Lakeland's financing team to issue tax exempt revenue bonds in order to provide funding for several projects listed in Lakeland's current capital forecast. As with any bond issue, this issue has been rated by the bond rating agencies. Lakeland had the bonds rated by Standard and Poor's Group (AA-) and Moody's Investors Service, Inc. (Aa). Lakeland has maintained these ratings since 1989 when the Moody's rating was upgraded to the current level.

The payments for operating costs of Lakeland's Department of Electric & Water Utilities are funded through revenue generated by the sale of electricity and water. The amount of revenue is in part determined by the rates charged for these products. The Department of Electric & Water Utilities, through its long range forecasts, identifies when rate increases are expected. These are identified years in advance of the actual need and are then implemented when, and at the level necessary to continue the financially sound operations of Lakeland. The City Commission for the City of Lakeland has the rate making authority for the Department of Electric & Water Utilities.

Detail revenue and expense budgets are prepared and reviewed each year. The approved budgets are then used to update the long range forecast to determine their impact on future years. This process has been very successful for Lakeland in avoiding unplanned rate increases. In fact, since 1989, Lakeland has been able to implement lower rate increases than originally forecast. Lakeland also believes that the Pressurized Circulating Fluidized Bed generator that this project will involve will operate more efficiently than any of its current generators, further strengthening Lakeland's financial position, and aiding it in providing cost effective power to its customers. The revenue anticipated from operating the new generator is based on the expected demand from existing customers and is not contingent on any future negotiations or sales to another utility.

Project Organization

The City of Lakeland is anticipating entering into an engineer, procure, construct (EPC) contract with a Foster Wheeler/Westinghouse consortium for the entire McIntosh Unit 4 PCFB project with the exception of certain specific items such as a 90 car unit train that would be handled by Lakeland's staff. Through the execution of a single EPC contract, Lakeland would have a single point of contact and single point of responsibility for all issues associated with the project. In order to assist Lakeland in reviewing and monitoring the performance of the EPC contractor, Lakeland is in the process of entering into an additional contract with a company who will act as the "Owner's Engineer". This company will safeguard Lakeland's interest on the project and conduct an ongoing prudency review.

In order to obtain the required permits and licenses for the construction and operation of McIntosh Unit 4, the City of Lakeland has retained the services of a qualified environmental consulting firm with particular expertise in the state of Florida. This same firm will be empowered to prepare the necessary information required by DOE to complete the NEPA process and is expected to liaise closely with DOE's chosen NEPA consultant or subcontractor.

Project Status

At the time this paper was written, DOE had recently announced approval of the project and efforts were underway to have all the Cooperative Agreements and related project agreements formally executed by the parties. Completion of this activity will trigger the formal start of Phase 1 of the McIntosh Unit 4 project. In parallel with this activity, the scope of work of each of the project participants, and their role within the project structure, is currently being fine tuned and finalized. The agreements necessary for each project participant to fulfil their project obligations are in the process of being negotiated. Two important project activities that will be initiated shortly are the permitting and NEPA activities.

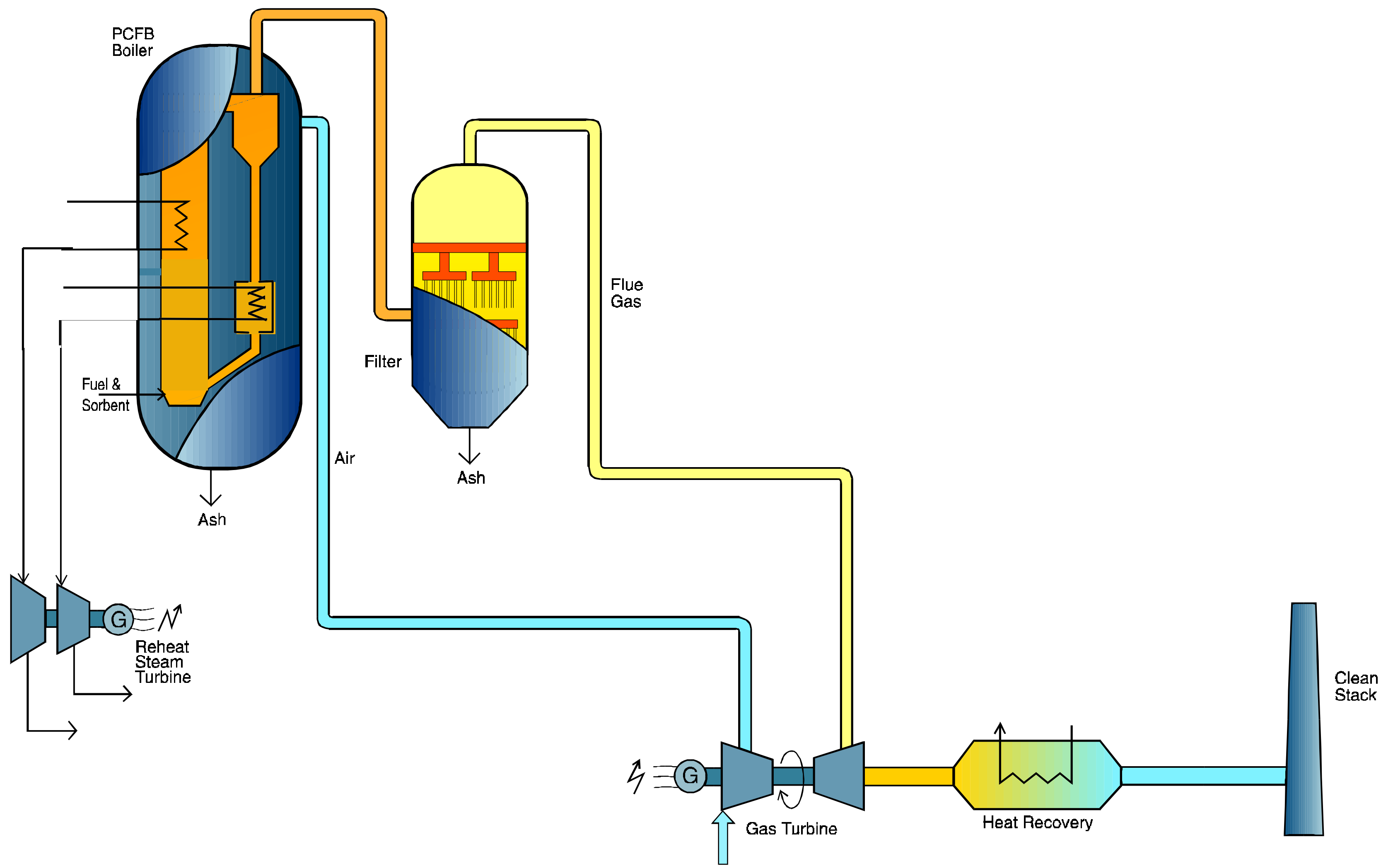


Figure 1.
PCFB Cycle - 1st Demonstration

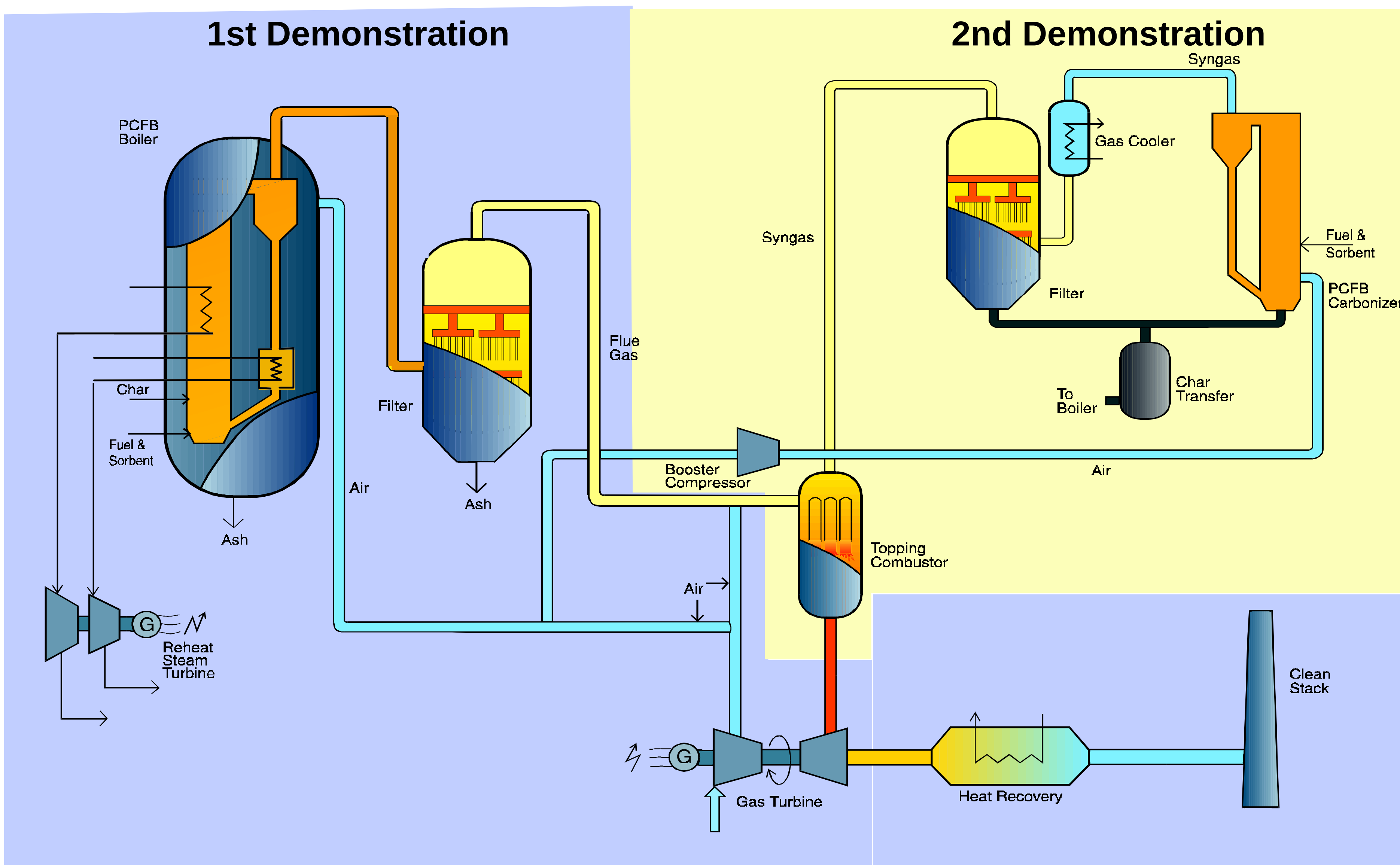
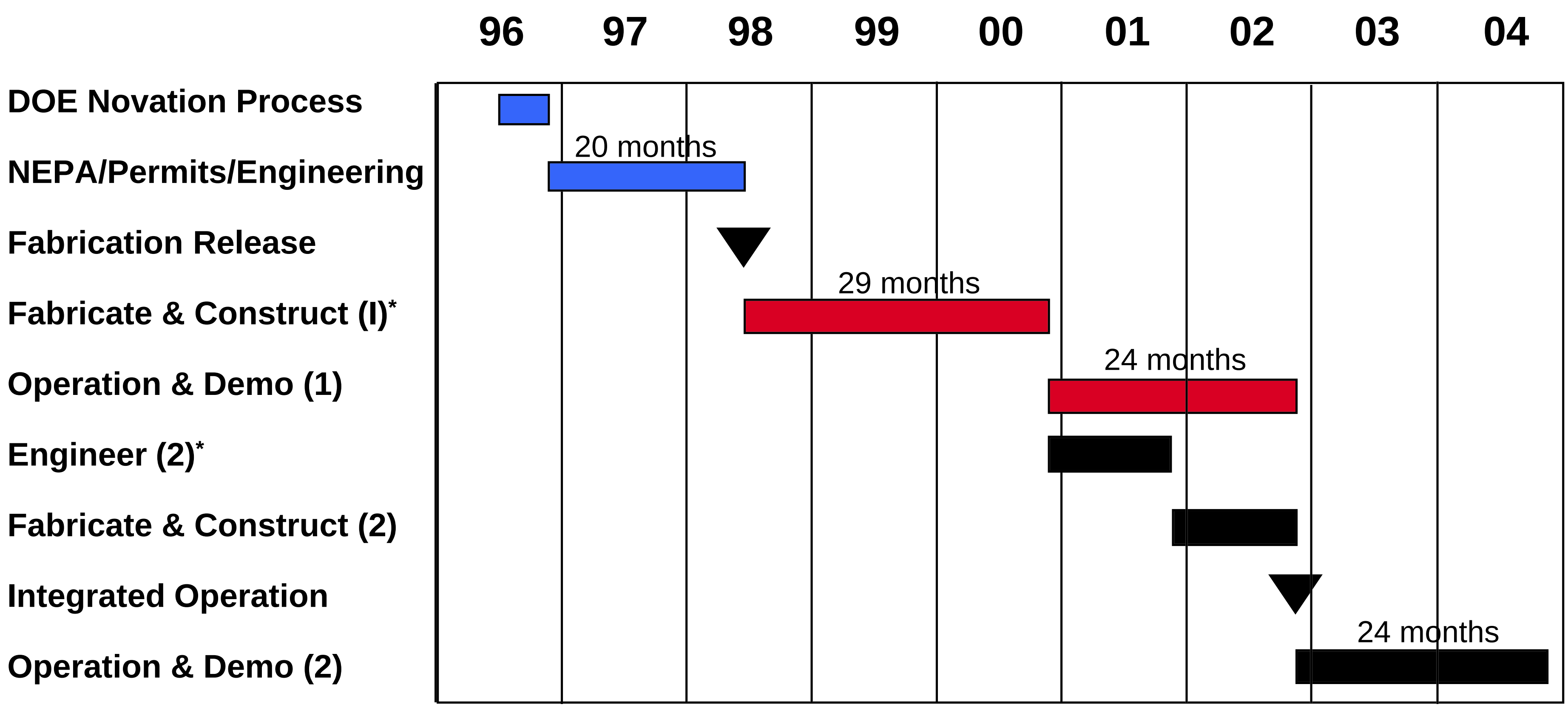


Figure 2
Topping PCFB Cycle - 2nd Demonstration

Figure 3
McIntosh Unit 4 Summary Schedule



*** (1) refers to 1st Demonstration and (2) to 2nd Demonstration**